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AEP Places Carbon Capture Commercialization On Hold, Citing Uncertain Status Of Climate Policy, Weak Economy

COLUMBUS, Ohio, July 14, 2011 – American Electric Power (NYSE: AEP) is terminating its cooperative agreement with the U.S. Department of Energy and placing its plans to advance carbon dioxide capture and storage (CCS) technology to commercial scale on hold, citing the current uncertain status of U.S. climate policy and the continued weak economy as contributors to the decision.

"We are placing the project on hold until economic and policy conditions create a viable path forward," said Michael G. Morris, AEP chairman and chief executive officer. "With the help of Alstom, the Department of Energy and other partners, we have advanced CCS technology more than any other power generator with our successful two-year project to validate the technology. But at this time it doesn't make economic sense to continue work on the commercial-scale CCS project beyond the current engineering phase.

"We are clearly in a classic 'which comes first?' situation," Morris said. "The commercialization of this technology is vital if owners of coal-fueled generation are to comply with potential future climate regulations without prematurely retiring efficient, cost-effective generating capacity. But as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share."

In 2009, AEP was selected by the Department of Energy (DOE) to receive funding of up to $334 million through the Clean Coal Power Initiative to pay part of the costs for installation of a commercial-scale CCS system at AEP's Mountaineer coal-fueled power plant in New Haven, W.Va. The system would capture at least 90 percent of the carbon dioxide (CO2) from 235 megawatts of the plant's 1,300 megawatts of capacity. The captured CO2, approximately 1.5 million metric tons per year, would be treated and compressed, then injected into suitable geologic formations for permanent storage approximately 1.5 miles below the surface.

Plans were for the project to be completed in four phases, with the system to begin commercial operation in 2015. AEP has informed the DOE that it will complete the first phase of the project (front-end engineering and design, development of an environmental impact statement and development of a detailed Phase II and Phase III schedule) but will not move to the second phase.

DOE's share of the cost for completion of the first phase is expected to be approximately $16 million, half the expenses that qualify under the DOE agreement.

AEP and partner Alstom began operating a smaller-scale validation of the technology in October 2009 at the Mountaineer Plant, the first fully-integrated capture and storage facility in the world. That system captured up to 90 percent of the CO2 from a slipstream of flue gas equivalent to 20 megawatts of generating capacity and injected it into suitable geologic formations for permanent storage approximately 1.5 miles below the surface. The validation project, which received no federal funds, was closed as planned in May after meeting project goals. Between October 2009 and May 2011, the life of the validation project, the CCS system operated more than 6,500 hours, captured more than 50,000 metric tons of CO2 and permanently stored more than 37,000 metric tons of CO2.

"The lessons we learned from the validation project were incorporated into the Phase I engineering for the commercial-scale project," Morris said.

American Electric Power is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

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Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a New Source Construction and Part 70 Permit

Source Description and Location

Source Name:	**Indiana Gasification, LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Operation Permit Issuance Date:	**Yet to be Issued**
Permit Reviewer:	**Josiah Balogun**

The Office of Air Quality (OAQ) has reviewed a New Source Construction and Part 70 operating permit application submitted by Indiana Gasification LLC, on April 20, 2011, in relating to the construction and operation of a state - of- the - art substitute natural gas ("SNG") and liquefied carbon dioxide ("CO2") production plant.

History

The proposed facility is designed to convert Illinois Basin coal and petroleum coke into pipeline-quality SNG and liquefied CO_2. The project will produce up to 48 billion standard cubic feet (Bscf) of SNG annually utilizing approximately 3.5 million tons of feedstock. About 39 Bscf will be sold to the Indiana Finance Authority ("IFA") for use by Indiana natural gas consumers with the remaining sold in the natural gas marketplace. The project will also produce annually up to approximately 6.43 million tons of liquefied CO_2 that will be sold to third parties for use in Enhanced Oil Recovery ("EOR") where it is estimated to produce approximately 10,000,000 barrels per year of additional domestic oil in the Gulf Coast region.

Facility development is supported by an agreement with the IFA regarding the purchase of the SNG production and a loan guarantee currently being negotiated with the Department of Energy, which is intended to encourage advanced coal gasification facilities. As a result, the project must conform to any provisions in contracts relating to these agreements.

The facility will have several products in addition to SNG and liquefied CO_2. Sulfur compounds in the feedstocks will be processed into sulfuric acid, which IG plans to sell into the industrial market. Argon will be recovered from the air separation unit and sold to one or more industrial gas companies. Heat generated during the gasification process will be used to produce steam for steam turbines that can produce approximately 300 MW, primarily to meet on-site power needs. Depending on process and ambient conditions, a small amount of power will be exported into or imported from the nearby electrical transmission system.

Existing Approvals

There have been no previous approvals issued to this source.

County Attainment Status

The source is located in Spencer County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective June 15, 2004, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
$PM_{2.5}$	Attainment effective November 2, 2011, for the annual PM2.5 standard for the Evansville area, including Ohio Township of Spencer County.
Pb	Not designated.
[1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005.	

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NOx emissions are considered when evaluating the rule applicability relating to ozone. Spencer County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
Spencer County has been classified as attainment for $PM_{2.5}$. On May 8, 2008, U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ emissions. These rules became effective on July 15, 2008. On May 4, 2011 the air pollution control board issued an emergency rule establishing the direct $PM_{2.5}$ significant level at ten (10) tons per year. This rule became effective, November 2, 2011. Therefore, direct $PM_{2.5}$ and SO_2 emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. See the State Rule Applicability – Entire Source section.

(c) Other Criteria Pollutants
Spencer County has been classified as attainment or unclassifiable in Indiana for all other pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this source is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Description of New Source and Emission Units with Control Equipment Summary

The Office of Air Quality (OAQ) has reviewed a New Source Construction application, submitted by Indiana Gasification, LLC on April 20, 2011, relating to the construction and operation of a state - of- the - art substitute natural gas ("SNG") and liquefied carbon dioxide ("CO_2") production plant. The proposed facility is designed to convert Illinois Basin coal and petroleum coke into pipeline-

quality SNG and liquefied CO_2. The project will produce up to 48 billion standard cubic feet (Bscf) of SNG annually utilizing approximately 3.5 million tons of feedstock. The project will also produce annually approximately 4.9 million tons of liquefied CO_2 that will be sold to third parties for use in Enhanced Oil Recovery ("EOR") where it is estimated to produce approximately 10,000,000 barrels per year of additional domestic oil in the Gulf Coast region. The following is a list of the proposed emission unit(s) and pollution control device(s):

(A) Incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins, consisting of: [Under 40 CFR 60, Subpart Y, the incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins are new affected sources.]

(1) One (1) barge unloading to hopper transfer point, to be permitted in 2012, nominally rated at 750 tons per hour, identified as EU-012A, with particulate emissions controlled by wet suppression.

(2) The following twenty (20) transfer points, each with particulate emissions controlled with a dust extraction system or baghouse nominally rated at 1,500 acfm:

(a) One (1) barge unloading from the hopper to the belt, identified as EU-012B, to be permitted in 2012, with one (1) control device, identified as C-012B, exhausting through one (1) vent, identified as S-012B;

(b) Four (4) barge conveyor transfer points, identified as EU-012C through EU-012F, to be permitted in 2012, with four (4) control devices, identified as C-012C through C-012F, respectively, exhausting through four (4) vents, identified as S-012C through S-012F, respectively;

(c) Two (2) rail unloading to rail hoppers, identified as EU-012G and EU-012H, to be permitted in 2012, with two (2) control devices, identified as C-012G through C-012H, respectively, exhausting through two (2) vents, identified as S-012G through S-012H, respectively;

(d) Two (2) rail hoppers unloading to the conveyor belts, identified as EU-012I and EU-012J, to be permitted in 2012, with two (2) control devices, identified as C-012I and C-012J, respectively, exhausting through two (2) vents, identified as S-012I through S-012J, respectively;

(e) One (1) rail conveyor belt to the stacker, identified as EU-012K, to be permitted in 2012, with one (1) control device, identified as C-012K, exhausting through one (1) vent, identified as S-012K;

(f) Two (2) stacker belts to the radial stacker, identified as EU-012L and EU-012M, to be permitted in 2012, with two (2) control devices, identified as C-012L and C-012M, respectively, exhausting through two (2) vents, identified as S-012L through S-012M, respectively;

(g) Two (2) classification towers, identified as EU-012T and EU-012U, to be permitted in 2012, with two (2) control devices, identified as C-012T and C-012U, respectively, exhausting through two (2) vents, identified as S-012T through S-012U, respectively;

(h) One (1) classification tower to a day bin, identified as EU-012V, to be permitted in 2012, with one (1) control device, identified as C-012V, exhausting through one (1) vent, identified as S-012V;

(i) Three (3) truck stations unloading to a truck hopper, identified as EU-012Z, EU-012AB and EU-012AC, to be permitted in 2012, with three (3) control devices, identified as C-012Z, C-012AB and C-012AC, respectively, exhausting through three (3) vents, identified as S-012Z, S-012AB and S-012AC, respectively;

(j) One (1) truck hopper unloading to the conveyor belts, identified as EU-012AA, to be permitted in 2012, with one (1) control device, identified as C-012AA exhausting through one (1) vent, identified as S-012AA; and

(k) One (1) truck/rail conveyor transfer tower, identified as EU-012Y, to be permitted in 2012, with one (1) control device, identified as C-012Y, exhausting through one (1) vent, identified as S-012Y;

(3) Two (2) radial stackers to the pile, nominally rated at 3,000 tons per hour each, to be permitted in 2012, with particulate emissions controlled by telescoping chutes with two (2) fabric filters identified as C-012N and C-012O, exhausting through two (2) stacks, identified as S-012N and S-012O.

(4) Two (2) transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers, identified as EU-012R and EU-012S, to be permitted in 2012, with particulate emissions controlled with two (2) dust extraction systems or baghouses, identified as C-012R and C-012S, respectively, each nominally rated at 6,000 acfm, exhausting through two (2) vents, identified as S-012R and S-012S, respectively.

(5) Two (2) dozer activities on the piles, nominally rated at 1,500 tons per hour each, identified as EU-012P and EU-012Q, to be permitted in 2012, with particulate emissions controlled by wet suppression.

(6) Two (2) storage piles with a nominal capacity of 300,000 tons each, identified as EU-012W and EU-012X, to be permitted in 2012, with particulate emissions controlled by wet suppression and compaction.

(B) Two (2) process area solid feedstock conveying, storage, and feed bins (main and spare), identified as EU-011A and EU-011B, to be permitted in 2012, with particulate emissions controlled by two (2) baghouses identified as C-011A and C-011B, respectively, each nominally rated at 33,760 dscfm, exhausting through two (2) stacks, identified as S-011A and S-011B, respectively. [Under 40 CFR 60, Subpart Y, the process area solid feedstock conveying, storage, and feed bins (main and spare) are new affected sources.]

(C) One (1) syngas hydrocarbon flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-001, to be permitted in 2012, exhausting through one (1) tip, identified as S-001.

(D) One (1) acid gas flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-002, to be permitted in 2012, exhausting through one (1) tip, identified as S-002.

(E) Two (2) Acid Gas Removal (AGR) Unit vents, identified as EU-007A and EU-007B, to be permitted in 2012, with methanol, H_2S, COS, and CO emissions controlled by two (2) regenerative thermal oxidizers (RTO) identified as C-007A and C-007B, respectively, each nominally rated at 38.8 MMBtu/hr HHV fuel input, exhausting through two (2) stacks, identified as S-007A and S-007B.

(F) Two (2) Wet Sulfuric Acid (WSA) plant trains, each nominally rated at 800 stpd H_2SO_4 and identified as EU-015A and EU-015B, to be permitted in 2012, with NO_x, SO_2, H_2SO_4 emissions controlled by two (2) selective catalytic reduction (SCR) systems identified as C-015-1A and C-015-1B, respectively, and two (2) hydrogen peroxide scrubbers identified as C-015-2A and C-015-2B, respectively, exhausting through two (2) stacks, identified as

S-015A and S-015B respectively. These emissions units also include two (2) preheat burners (one for each train), each nominally rated at 35.00 MMBtu/hr HHV, venting through the same stacks.

(G) Two (2) natural gas-fired auxiliary boilers, nominally rated at 408 MMBtu/hr HHV each, identified as EU-005A and EU-005B, to be permitted in 2012, with NO_x emissions controlled by ultra-low NO_x burners/Flue Gas Recirculation (ULNB/FGR), with both boilers exhausting through one (1) stack, identified as S-005. [Under 40 CFR 60, Subpart Db, the natural gas-fired auxiliary boilers are new affected sources.]

(H) Five (5) natural gas-fired and SNG fuel-fired gasifier preheat burners, each nominally rated with a heat input of 35.00 MMBtu/hr HHV, and identified as EU-008A through EU-008E, to be permitted in 2012, exhausting through five (5) vents, identified as S-008A through S-008E, respectively.

(I) One (1) ZLD-Spray Dryer, to be permitted in 2012, nominally rated at 5.6 MMBtu/hr with PM emissions controlled by a baghouse identified as C-032, nominally rated at 2,735 dscfm, and identified as EU-032, with low NOx burners (LNB), exhausting through one (1) stack, identified as S-014.

(J) Methanol Tanks:

(1) One (1) Methanol De-Inventory Tank, with a nominal capacity of 700,000 gallons, identified as EU-024, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-024. [40 CFR 60 Subpart Kb].

(2) One (1) Fresh Methanol Storage Tank, with a nominal capacity of 332,000 gallons, identified as EU-025, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-025. [40 CFR 60 Subpart Kb].

(K) Paved Plant Haul Roads are identified as emissions unit FUG-ROAD.

(L) Electrical Circuit Breakers (approximately six) containing sulfur hexafluoride (SF_6) identified as emissions unit FUG-SF6, to be permitted in 2012, with fugitive GHG emissions controlled by full enclosure.

(M) Fugitive Equipment Leaks from the gasification, shift conversion, gas cooling, AGR, CO_2 compression, WSA and methanation are identified as emissions units FUG and FUG-WSA and will be controlled by a Leak Detection and Repair (LDAR) program.

(N) One (1) ZLD Inert Gas Vent identified as EU-033, to be permitted in 2012, with mercury (Hg) emissions controlled by a sulfided carbon adsorbent identified as C-033, exhausting through one (1) stack, identified as S-033.

Insignificant and Trivial Activities

The source also consists of the following insignificant activities as defined in 326 IAC 2-7-1(21):

(a) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, to be permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, each, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each, emergency diesel fired generator is considered a new affected source.]

(b) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, to be permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, each firewater pump diesel engine is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each firewater pump diesel engine is considered a new affected source.]

(c) Four (4) rod mill eductor vent stacks, to be permitted in 2012, nominally rated at 180 cfm and identified as EU-013A through EU-013D, and exhausting through four (4) vents, identified as S-013A through S-013D, respectively.

(d) One (1) six (6) cell ASU cooling tower, nominally rated with a circulation rate of 54,960 gpm and identified as EU-016A, to be permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through six (6) vents, identified as S-016A-A through S-016A-F.

(e) One (1) twenty-four (24) cell main cooling tower, nominally rated with a circulation rate of 404,700 gpm and identified as EU-016B, to be permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through twenty-four (24) vents, identified as S-016B-A through S-016B-X.

(f) Two (2) Air Separation Unit (ASU) molecular sieve regeneration train vents, which each vent a nominal 187,000 cubic feet per minute during regenerations, identified as EU-017A and EU-017B, to be permitted in 2012, exhausting through two (2) vents, identified as S-017A andS-017B, respectively.

(g) One (1) slag handling storage pad, to be permitted in 2012, nominally rated at 43 tons per hour, identified as EU-034A, with fugitive particulate emissions controlled by wet suppression.

(h) One (1) front-end loader activity on the slag storage pad, to be permitted in 2012, nominally rated at 1,440 tons per day, identified as EU-034C, with fugitive particulate emissions controlled by wet suppression.

(i) One (1) fixed roof recycle solid tank, to be permitted in 2012, with a nominal capacity of 14,400 gallons, identified as EU-019.

(j) Five (5) fixed roof slurry run tanks, each, to be permitted in 2012, with a nominal capacity of 47,700 gallons, identified as EU-020A through EU-020E.

(k) Two (2) fixed roof grey water tanks, to be permitted in 2012, each with a nominal capacity of 88,000 gallons, identified as EU-021A and EU-021B.

(l) One (1) fixed roof slurry additive tank, to be permitted in 2012, with a nominal capacity of 28,500 gallons, identified as EU-022.

(m) Five (5) open slag sumps, to be permitted in 2012, each with a nominal capacity of 15,600 gallons, identified as EU-023A through EU-023E.

(n) One (1) pressurized Sour Water Stripper Surge Tank, to be permitted in 2012, with a nominal capacity of 175,000 gallons, identified as EU-026.

(o) Six (6) fixed roof sulfuric acid storage tanks, to be permitted in 2012, each with a nominal capacity of 866,500 gallons - identified as EU-027A through EU-027F.

(p) Two (2) fixed roof aqueous ammonia storage tanks, to be permitted in 2012, each with a nominal capacity of 31,000 gallons - identified as EU-028A and EU-028B, with ammonia emissions controlled with two (2) water scrubbers identified as C-028A and C-028B, respectively.

(q) One (1) fixed roof Diesel Fuel Storage Tank, to be permitted in 2012, with a nominal capacity of 9,240 gallons, identified as EU-029.

(r) One (1) fixed roof Gasoline Fuel Storage Tank, to be permitted in 2012, with a nominal capacity of 1,030 gallons, identified as EU-030.

(s) One (1) fixed roof triethylene glycol storage tank, to be permitted in 2012, with a nominal capacity of less than 10,000 gallons, identified as EU-031.

Enforcement Issues

There are no pending enforcement actions.

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Unrestricted Potential Emissions – Part 70

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as "the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency."

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

PTE Before Controls	
Pollutant	**Potential To Emit (ton/yr)**
PM	322.93
PM_{10}	207.09
$PM_{2.5}$	73.63
SO_2	119.9
VOC	90.26
CO	302,916
NO_X	588.4
H_2SO_4	43.89
H_2S	12.3
Pb	0.04
Hg	0.07
GHGs as CO_2e	3,094,536 (Note 1)

HAPs	Potential To Emit (tons/year)
Methanol	17.98
Lead	0.04
Beryllium	0.000059
Mercury	0.07
Manganese	< 10
Chlorine	< 10

HAPs	Potential To Emit (tons/year)
Formaldehyde	< 10
other HAPs	greater than 10
Total HAPs	greater than 25

Note 1: The above GHG emissions reflect the PTE in operating Year 3 and beyond. The PTE Year 1 estimated as 6,494,536 tons/yr CO2e. The PTE Year 2 estimated as 8,234,536 tons/yr CO2e.

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM_{10}, $PM_{2.5}$, SO_2, CO and NOx are equal to or greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit.

(b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of GHGs is equal to or greater than one hundred thousand (100,000) tons of CO_2 equivalent emissions (CO_2e) per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit.

(c) The potential to emit (as defined in 326 IAC 2-7-1(29)) of all other regulated pollutants are less than 100 tons per year.

(d) The potential to emit (as defined in 326 IAC 2-7-1(29)) of any single HAP is equal to or greater than ten (10) tons per year and the potential to emit (as defined in 326 IAC 2-7-1(29)) of a combination of HAPs is equal to or greater than twenty-five (25) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

Actual Emissions

No previous emission data has been received from the source.

Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

(b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

Permit Level Determination – PSD

The table below summarizes the potential to emit, reflecting all limits, of the emission units at Indiana Gasification, LLC. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

	Potential to Emit (ton/yr)													
Process / Emission Unit	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO	NOx	H_2SO_4	H_2S	Pb	Hg	Metha-nol	Total HAPs	Total GHG CO_2e
Syngas Hydrocarbon Flare-001	0.44	0.44	0.41	1.97	0.03	23.5	6.07	0	0.04	3E-06	1.9E-06	0	0	13,343
Acid Gas Flare - 002	0.01	0.01	0.01	0.001	0.023	0.06	0.23	0	0	3E-06	1.9E-06	0	0	136
Auxiliary Boiler (A-B) -005	5.62	5.62	5.62	0.44	4.07	27.15	9.43	0	0	2E-03	1.3E-03	0	1.4	88,254
Acid Gas Recovery Unit (A-B) -007	2.46	2.46	2.46	26.98	8.96	410.27	16.85	0	0.1	9.6E-0.4	5.5E-04	9.0	22.5	1,290,000
Gasifier Preheat Burners (A-E) -008	0.04	0.04	0.04	0.03	0.3	3.08	5.51	0	0	1.6E-04	9.0E-05	0	0.1	6444
Emergency Diesel Generators (A-B) - 009	0.003	0.003	3E-04	0.008	0.015	0.019	0.76	0	0	0	0	0	0	84
Emergency Firewater pumps (A-C) - 010	0.008	0.008	8E-03	5E-04	0.017	0.06	0.24	0	0	0	0	0	0	
Process Area Solid Feedstock Handling (Coal/Petcoke) - 011	3.8	3.8	1.86	0	0	0	0	0	0	1.1E-03	5.5E-06	0	0	0
Incoming Solid Feed stock handling (Coal/petcoke) (A-	5.45	3.25	0.88	0	0	0	0	0	0	0	8.9E-06	0	0	0

	Potential to Emit (ton/yr)													
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**	**CO**	**NOx**	**H_2SO_4**	**H_2S**	**Pb**	**Hg**	**Metha-nol**	**Total HAPs**	**Total GHG CO_2e**
AC) - 012														
Rod Mill (A-D) -013	0.44	0.44	0.13	0	0	0	0	0	0	0	3.8E-07	0	0	0
Wet Sulfuric Acid Plant (A-B) - 015	42.6	42.6	42.6	70.74	0.01	159.7	86.93	42.6	0	6E-06	3.5E-06	0	0	474,000
Cooling Tower - ASU - 016A	0.9	0.9	0.70	0	0	0	0	0	0	0	0	0	0	0
Cooling Tower - Main - 016B	6.65	6.65	5.19	0	0	0	0	0	0	0	0	0	0	0
ASU Molecular Sieve Regeneration (A-B) - 017	0.22	0.22	0.08	0	0	0	0	0	0	0	0	0	0	0
Slag Sump (A-E) - 023	0	0	0	0	0	0	0	0	0.1	0	0	0	0	0
Methanol Deinventory Tank - 024	0	0	0	0	0.16	0	0	0	0	0	0	0.16	0.16	0
Fresh Methanol Storage Tank - 025	0	0	0	0	0.13	0	0	0	0	0	0	0.13	0.13	0
Sour Water Striper Surge Tank - 026	0	0	0	0	0.004	0	0	0	0.54	0	0	0	0	0
Sulfuric Acid Storage Tank (A-F) - 027	0.0015	0.0015	0.0015	0	0	0	0	0.0015	0	0	0	0	0	0
Diesel Fuel Storage Tank - 029	0	0	0	0	0.35	0	0	0	0	0	0	0	0.07	0
Gasoline Fuel Storage Tank - 030	0	0	0	0	0.1	0	0	0	0	0	0	0	0	0

	Potential to Emit (ton/yr)													
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**	**CO**	**NOx**	**H_2SO_4**	**H_2S**	**Pb**	**Hg**	**Metha-nol**	**Total HAPs**	**Total GHG CO_2e**
Triethylene Glycol Storage Tank - 031	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ZLD Spray Dryer - 032	0.51	0.51	0.48	0.015	0.13	0.89	0.86	0	0	7E-05	4.1E-05	0	0.046	2886
ZLD Inert Gas Vent (033)	0	0	0	0	0	0	0	0	0	0	3.6E-04	0	0	203.7
EU-034A and EU-034C	0.04	0.017	0.0024	0	0	0	0	0	0	0	0	0	0	0
Fugitive Emissions														
Gasification, Shift Conv., AGR, Methanation - FUG	0	0	0	0	1.61	9.45	0	0	0.37	0	0	0.37	0.38	21
WSA - FUG-WSA	0	0	0	0.003	0	0	0	009	3.74	0	0	0	0	4
Plant Haul Road - FUG ROAD	0.45	0.09	0.022	0	0	0	0	0	0	0	0	0	0	0
Electric Circuit Breakers - FUG SF6	0	0	0	0	0	0	0	0	0	0	0	0	0	72
Total Emission for New Source Construction	**69.63**	**67.05**	**60.48**	**100.2**	**15.90**	**634.18**	**126.9**	**42.68**	**4.89**	**0.004**	**0.0023**	**9.66**	**24.79**	**1,875,448** (Note 2)
Nonattainment NSR Major Source Thresholds	--	--	100	100	--	--	--	--	--	--	--	--	--	--
Significant Level	**25**	**15**	**10**	**40**	**40**	**100**	**40**	**7**	**10**	**0.6**	**0.1**	**10**	**25**	**75,000**

Note 2: The above GHG emissions reflect the PTE in operating year three and beyond. The PTE Year 1 estimated as 5,275,448 tons/yr CO2e. The PTE Year 2 estimated as 7,015,448 tons/yr CO2e.

This new stationary source is a major stationary source, under PSD (326 IAC 2-2), because a regulated pollutant is emitted at a rate of 100 tons per year or more, emissions of GHGs are equal to or greater than one hundred thousand (>100,000) tons of CO_2 equivalent emissions (CO_2e) per year, which is greater than the PSD threshold and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(gg)(1). Therefore, pursuant to 326 IAC 2-2, the PSD requirements do apply to the new source.

Federal Rule Applicability Determination

The following federal rules are applicable to the source due to this New Source Construction:

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to new or modified emission units that involve a pollutant-specific emission unit and meet the following criteria:

(1) has a potential to emit before controls equal to or greater than the Part 70 major source threshold for the pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant; and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each new or modified emission unit involved:

CAM Applicability Analysis							
Emission Unit	**Control Device Used**	**Emission Limitation** (Y/N)	**Uncontrolled PTE** (ton/yr)	**Controlled PTE** (ton/yr)	**Part 70 Major Source Threshold** (ton/yr)	**CAM Applicable** (Y/N)	**Large Unit** (Y/N)
Syngas Hydrocarbon Flare -001 (CO)	N	Y	> 100	< 100	100	N	N
Auxiliary Boiler - 005 (CO)	N	Y	> 100	< 100	100	N	N
Acid Gas Recovery Unit (A-B) -007 (CO)	Y	Y	> 100	> 100	100	Y	Y
Wet Sulfuric Acid Plant (A-B) - 015 (NOx)	Y	Y	>100	< 100	100	Y	N
Wet Sulfuric Acid Plant (A-B) - 015 (SO_2)	Y	Y	>100	< 100	100	Y	N
Wet Sulfuric Acid Plant (A-B) - 015 (H_2SO_4)	Y	Y	> 100	< 100	100	Y	N

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are applicable to Wet Sulfuric Acid Plant (A-B) - 015 for NOx, SO_2 and H_2SO_4, the Acid Gas Recovery Unit (A-B) -007 for CO, upon start-up. A CAM plan has been submitted (See Appendix D for the detailed CAM Plan).

CAM does not apply to any other emission units at this source, either because their uncontrolled emissions rate is less than 100 tpy or because emissions are limited by inherent process equipment that is not considered a control device per the 40 CFR 64.1 definition of inherent process equipment.

(b) The requirements of Area Source MACT- National Emission Standards for Hazardous Air Pollutants – Industrial, Commercial, and Institutional Boilers at Area Sources 40 CFR Part 63 Subpart JJJJJJ recently promulgated for Industrial, Commercial, and Institutional Boilers (Area Boiler MACT) do not apply to the auxiliary boiler, identified as (E005). The final EPA

rule does not regulate area source boilers that fire only natural gas fuel – because they do not emit sufficient urban air toxics to require regulation. In the proposed rule preamble, EPA states: *". . . pursuant to section 112(c)(3) of the CAA, we are proposing emission standards for the above mentioned HAP for area source boilers fired by coal, oil, and wood, but not standards for boilers fired by natural gas.*" In the final rule Preamble EPA again clarified that *"Notably, gas-fired units are not included in the source category listing for area source boilers."*

(c) The requirements of Standards of Performance for Fossil-Fuel Fired Steam Generators for which construction is commenced after August 17, 1971 40 CFR 60, Subpart D are not applicable to any sources in this project. The requirements of this rule apply to steam-generating units that commence construction, modification, or reconstruction after August 17, 1971 and that have a heat input capacity from fuels combusted in the steam generating unit of greater than 73 MW (250 million Btu/hour). Although the auxiliary boilers (EU 005A/B) have a heat input capacity greater than 250 MMBtu/hr, each and are steam-generating units, pursuant to 40 CFR 60.40b(j) the auxiliary boilers are exempt from the requirements of NSPS Subpart D because they are instead subject to the requirements of NSPS Subpart Db.

The thermal oxidizers (EUs 007A, B) and the gasifier pre-heat burners (EUs 008A-E) have a maximum design heat input capacity less than 73 MW (250 MMBtu/hr) and they are not steam-generating units; therefore Subpart D does not apply to these sources.

(d) The requirements of Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978 40 CFR 60, Subpart Da do not apply to any emission units at the sources. The requirements of this rule apply to electric utility steam-generating units that commence construction, modification, or reconstruction after September 18, 1978, and that have a heat input capacity from fuels combusted in the steam-generating unit of greater than 73 MW (250 million Btu/hour). The auxiliary boilers, which can supply steam to an electric generating steam turbine are steam-generating units, but they are not considered electric utility units because they will not supply more than 1/3 of its potential electrical output capacity to any utility power distribution system.

The requirements of this rule 40 CFR 60, Subpart Da are not applicable to the thermal oxidizers (EUs 007A, B) or gasifier pre-heat burners (EUs 008A-E) since they do not meet the definition of an electric utility steam generating unit. Specifically, the thermal oxidizers and the pre-heat burners do not generate steam, and thus are not steam generating units.

(e) The requirements of Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units 40 CFR 60, Subpart Dc are not applicable to any of the emission units at source. The requirements of this rule are applicable to steam generating units for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 MMBtu/hr) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr). The auxiliary boilers (EU 005A/B) have a heat input capacity greater 100 MMBtu/hr; therefore Subpart Dc does not apply. The thermal oxidizers (EUs 007A, B) and the burners (EUs 008A-E) are not steam generating units; therefore, 40 CFR 60, Subpart Dc does not apply.

(f) **40 CFR Part 63 Subpart VVVVVV—National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources** While this facility is an area source of HAPs, This source is not subject to 40 CFR Part 63 Subpart VVVVVV because this rule only regulates facilities that use as feedstocks, generates as byproducts, or produces as products any of the hazardous air pollutants (HAP) listed in Table 1 to this subpart. This facility does not use any of the listed HAPs as a feedstock or generate them as products or byproducts.

(g) 40 CFR 60 Subparts VVa, III, NNN, RRR and YYY –Standards of Performance that apply to the Synthetic Organic Chemicals Manufacturing Industry. This facility does not

manufacturer any of the SOCMI chemicals listed in 40 CFR 60.489

(h) 40 CFR 60 Subparts J,GGGa, and QQQ – Standards of Performance that apply to petroleum refineries. This facility does not process petroleum and therefore does not meet the definition of petroleum refinery under these standards.

(i) 40 CFR 60 Subparts KKK and LLL – Standards of Performance that apply to natural gas processing facilities. These rules apply to facilities that extract and process natural gas liquids from field gas. This facility does not meet the definition of a natural gas processing facility under these two rules.

(j) The requirements of Standards of Performance for Sulfuric Acid Plants 40 CFR 60, Subpart H do not apply to the project's Sulfuric Acid Plant, because it does not meet the rule's definition of a sulfuric acid production unit. 40 CFR 60, Subpart H applies to sulfuric acid plants defined as follows (emphasis added):

(1) Sulfuric acid production unit means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans, or acid sludge, but does not include facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.

The Indiana Gasification, LLC Sulfuric Acid Plant is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfuric compounds. Therefore, it does not fit the applicability requirement shown above. The sulfuric acid facility is a sulfur recovery process which converts the sulfur compounds removed from the syngas in the AGR, thereby preventing their emissions to the atmosphere. The H_2S and COS in the acid gas stream from the Rectisol Process is combusted for conversion to SO_2. The SO_2 rich gas produced is sent to catalyst beds for conversion to SO_3 and then conversion to sulfuric acid (H_2SO_4) after reaction with water.

Therefore, the Indiana Gasification sulfuric acid plant does not meet the definition of sulfuric acid production unit as defined by 40 CFR 60, Subpart H and does not apply to the WSA stack vents (EUs 015A, B). This is further confirmed by an EPA applicability determination for an analogous sulfuric acid plant at a petroleum refinery. In this 1995 applicability memo (ADI control number 9600093), EPA states that a WSA that produces H_2SO_4 from H_2S is not covered by NSPS Subpart H.

(k) The requirements of Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984 40 CFR 60, Subpart Kb are not applicable to the following storage tanks listed below because the tanks do not store organic materials and have capacities and maximum true vapor pressure less than 151 cubic meters (m^3) and 3.5 kPa, respectively.

EU No.	Tank ID	Tank Capacity (Gal)	Max. Vapor Pressure Psia	40 CFR 60, Subpart Kb	Tank Vents to:
023 A	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 B	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 C	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 D	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 E	Slag Sump	25,284	1.52	No (1)	Atmosphere

EU No.	Tank ID	Tank Capacity (Gal)	Max. Vapor Pressure Psia	40 CFR 60, Subpart Kb	Tank Vents to:
027 A	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
027 B	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
027 C	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
027 D	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
027 E	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
027 F	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
028 A	Aqueous Ammonia Tank	32,243	5.38	No (1)	Atmosphere
028 B	Aqueous Ammonia Tank	32,243	5.38	No (1)	Atmosphere
030	Gasoline Tank	1,175	6.20	No (2)	Atmosphere

Note: (1) Tank does not store VOCs.
(2) This source is not subject to NSPS Subpart Kb because the tank does not meet the capacity criteria.

(l) The auxiliary boilers, identified as EU 005A and EU-5B are subject to the requirements of the New Source Performance Standard, 40 CFR 60, Subpart Db, Standard of Performance for Industrial -Commercial Institutional Steam Generating Unit, which is incorporated by reference as 326 IAC 12 because they are boilers that will commence construction, modification, or reconstruction after June 19, 1984, and that have a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)). The auxiliary boilers, identified as EU 005A and EU- 5B, each has a heat input capacity greater than 100 MMBtu/hr. The specific facilities subject to this rule includes the following.

(1) Two (2) natural gas-fired auxiliary boilers, nominally rated at 408 MMBtu/hr HHV each, identified as EU-005A and EU-005B, to be permitted in 2012, with NO_x emissions controlled by ultra-low NO_x burners/Flue Gas Recirculation (ULNB/FGR), with both boilers exhausting through one (1) stack, identified as S-005. [Under 40 CFR 60, Subpart Db, the natural gas-fired auxiliary boilers are new affected source.]

The boilers are subject to the following portions of Subpart Db:

(1) 40 CFR 60.40b(a);
(2) 40 CFR 60.40b(j);
(3) 40 CFR 60.41b(b);
(4) 40 CFR 60.42b(k)(2);
(5) 40 CFR 60.44b(h);
(6) 40 CFR 60.44b(i);
(7) 40 CFR 60.44b(l);
(8) 40 CFR 60.46b(a);
(9) 40 CFR 60.46b(c);
(10) 40 CFR 60.46b(e)(1);
(11) 40 CFR 60.46b(e)(3);
(12) 40 CFR 60.48b(b);
(13) 40 CFR 60.48b(c);
(14) 40 CFR 60.48b(d);
(15) 40 CFR 60.48b(e)(2);
(16) 40 CFR 60.48b(e)(3);
(17) 40 CFR 60.48b(f);

(18) 40 CFR 60.49b(a);
(19) 40 CFR 60.49b(b);
(20) 40 CFR 60.49b(d);
(21) 40 CFR 60.49b(g);
(22) 40 CFR 60.49b(i); and
(23) 40 CFR 60.49b(o).

NOTE: The auxiliary boilers will only fire natural gas or SNG. Therefore, Subpart Db will not impose any applicable PM_{10} or SO_2 emission standards. The Subpart Db NO_x standard applicable to these sources, high heat release boilers, is 0.10 lb/MMBtu (per 40 CFR 60.44b (a) (1) (ii)). This emission limit is less restrictive than the proposed Best Available Control Technology (BACT) limit discussed in Section 5. NO_x emission will be controlled with the use of ultra low NO_x burners and flue gas recirculation.

Compliance testing will be performed per 40 CFR 60.46b(e). NOx monitoring will be accomplished using a continuous emission monitoring system (CEMS) per 40 CFR 60.48b(b)(1).

(m) The requirements of Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984 40 CFR 60, Subpart Kb are applicable to the Methanol Deinventory Tank, Identified as 024 and the fresh Methanol Storage Tank, identified as 025 because they store organic materials, will have commenced construction after July 23, 1984, have capacities greater than 151 cubic meters (m^3) (39,889 gallons) and store only volatile organic compounds with a maximum true vapor pressure greater than 3.5 kPa. The specific facilities subject to this rule includes the following.

(A) Methanol Tanks:

(1) One (1) Methanol De-Inventory Tank, with a nominal capacity of 700,000 gallons, identified as EU-024, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-024. [40 CFR 60 Subpart Kb].

(2) One (1) Fresh Methanol Storage Tank, with a nominal capacity of 332,000 gallons, identified as EU-025, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-025. [40 CFR 60 Subpart Kb].

The storage tanks are subject to the following portions of Subpart Kb:

(1) 40 CFR 60.110b(a);
(2) 40 CFR 60.110b(e);
(3) 40 CFR 60.111b;
(4) 40 CFR 60.112b(a)(3);
(5) 40 CFR 60.112b(a)(4);
(6) 40 CFR 60.113b(c);
(7) 40 CFR 60.114b(c);
(8) 40 CFR 60.115b(c);
(9) 40 CFR 60.116b(a);
(10) 40 CFR 60.116b(b);
(11) 40 CFR 60.116b(e); and
(12) 40 CFR 60.116b(g).

(n) The source is subject to the New Source Performance Standard - Standards of Performance for Coal Preparation and Processing Plants, 40 CFR 60, Subpart Y, which is incorporated by reference as 326 IAC 12. These requirements apply to facilities that prepare coal by one of more of several listed processes and which process more than 161

mega-grams per day (200 tons per day) of coal and commenced construction after May 27, 2009. The activities regulated by this NSPS include crushing, screening, conveying, and transferring of coal. The specific facilities subject to this rule include the following.

(A) Incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins, consisting of: [Under 40 CFR 60, Subpart Y, the incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins are new affected sources.]

(1) One (1) barge unloading to hopper transfer point, to be permitted in 2012, nominally rated at 750 tons per hour, identified as EU-012A, with particulate emissions controlled by wet suppression.

(2) The following twenty (20) transfer points, each with particulate emissions controlled with a dust extraction system or baghouse nominally rated at 1,500 acfm:

(a) One (1) barge unloading from the hopper to the belt, identified as EU-012B, to be permitted in 2012, with one (1) control device, identified as C-012B, exhausting through one (1) vent, identified as S-012B;

(b) Four (4) barge conveyor transfer points, identified as EU-012C through EU-012F, to be permitted in 2012, with four (4) control devices, identified as C-012C through C-012F, respectively, exhausting through four (4) vents, identified as S-012C through S-012F, respectively;

(c) Two (2) rail unloading to rail hoppers, identified as EU-012G and EU-012H, to be permitted in 2012, with two (2) control devices, identified as C-012G through C-012H, respectively, exhausting through two (2) vents, identified as S-012G through S-012H, respectively;

(d) Two (2) rail hoppers unloading to the conveyor belts, identified as EU-012I and EU-012J, to be permitted in 2012, with two (2) control devices, identified as C-012I and C-012J, respectively, exhausting through two (2) vents, identified as S-012I through S-012J, respectively;

(e) One (1) rail conveyor belt to the stacker, identified as EU-012K, to be permitted in 2012, with one (1) control device, identified as C-012K, exhausting through one (1) vent, identified as S-012K;

(f) Two (2) stacker belts to the radial stacker, identified as EU-012L and EU-012M, to be permitted in 2012, with two (2) control devices, identified as C-012L and C-012M, respectively, exhausting through two (2) vents, identified as S-012L through S-012M, respectively;

(g) Two (2) classification towers, identified as EU-012T and EU-012U, to be permitted in 2012, with two (2) control devices, identified as C-012T and C-012U, respectively, exhausting through two (2) vents, identified as S-012T through S-012U, respectively;

(h) One (1) classification tower to a day bin, identified as EU-012V, to be permitted in 2012, with one (1) control device, identified as C-012V, exhausting through one (1) vent, identified as S-012V;

(i) Three (3) truck stations unloading to a truck hopper, identified as EU-012Z, EU-012AB and EU-012AC, to be permitted in 2012, with three (3) control devices, identified as C-012Z, C-012AB and C-012AC,

respectively, exhausting through three (3) vents, identified as S-012Z, S-012AB and S-012AC, respectively;

(j) One (1) truck hopper unloading to the conveyor belts, identified as EU-012AA, to be permitted in 2012, with one (1) control device, identified as C-012AA exhausting through one (1) vent, identified as S-012AA; and

(k) One (1) truck/rail conveyor transfer tower, identified as EU-012Y, to be permitted in 2012, with one (1) control device, identified as C-012Y, exhausting through one (1) vent, identified as S-012Y;

(3) Two (2) radial stackers to the pile, nominally rated at 3,000 tons per hour each, to be permitted in 2012, with particulate emissions controlled by telescoping chutes with two (2) fabric filters identified as C-012N and C-012O, exhausting through two (2) stacks, identified as S-012N and S-012O.

(4) Two (2) transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers, identified as EU-012R and EU-012S, to be permitted in 2012, with particulate emissions controlled with two (2) dust extraction systems or baghouses, identified as C-012R and C-012S, respectively, each nominally rated at 6,000 acfm, exhausting through two (2) vents, identified as S-012R and S-012S, respectively.

(5) Two (2) dozer activities on the piles, nominally rated at 1,500 tons per hour each, identified as EU-012P and EU-012Q, to be permitted in 2012, with particulate emissions controlled by wet suppression.

(6) Two (2) storage piles with a nominal capacity of 300,000 tons each, identified as EU-012W and EU-012X, to be permitted in 2012, with particulate emissions controlled by wet suppression and compaction.

(B) Two (2) process area solid feedstock conveying, storage, and feed bins (main and spare), identified as EU-011A and EU-011B, to be permitted in 2012, with particulate emissions controlled by two (2) baghouses identified as C-011A and C-011B, respectively, each nominally rated at 31,870 dscfm, exhausting through two (2) stacks, identified as S-011A and S-011B, respectively. [Under 40 CFR 60, Subpart Y, the process area solid feedstock conveying, storage, and feed bins (main and spare) are new affected sources.]

The source is subject to the following portions of Subpart Y.

(1) 40 CFR 60.250(a);
(2) 40 CFR 60.250(d);
(3) 40 CFR 60.251;
(4) 40 CFR 60.254(b);
(4) 40 CFR 60.254(c);
(5) 40 CFR 60.255(b);
(6) 40 CFR 60.255(c);
(7) 40 CFR 60.255(d);
(8) 40 CFR 60.255(e);
(9) 40 CFR 60.255(f);
(10) 40 CFR 60.255(g);
(11) 40 CFR 60.255(h);
(12) 40 CFR 60.256(b)(1);
(13) 40 CFR 60.256(b)(3);
(14) 40 CFR 60.256(c);
(15) 40 CFR 60.257(a);
(16) 40 CFR 60.258(a)(1);

(17) 40 CFR 60.258(a)(2);
(18) 40 CFR 60.258(a)(3);
(19) 40 CFR 60.258(a)(4);
(20) 40 CFR 60.258(a)(5);
(21) 40 CFR 60.258(a)(6);
(22) 40 CFR 60.258(a)(7);
(23) 40 CFR 60.258(a)(8);
(24) 40 CFR 60.258(a)(10);
(25) 40 CFR 60.258(b)(2);
(26) 40 CFR 60.258(b)(3);
(27) 40 CFR 60.258(c); and
(28) 40 CFR 60.258(d).

(o) The source is subject to the requirements of 40 CFR, Subpart IIII - Standard of Performance for Stationary Compression Ignition Internal Combustion Engines because the emergency generators and the firewater diesel pump will be constructed after July 11, 2005 and manufactured after April 1, 2006. The specific facilities subject to this rule includes the following.

(a) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, to be permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, emergency diesel fired generator is considered a new affected source.].

(b) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, to be permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, emergency diesel fired generator is considered a new affected source.].

The emergency generator and the firewater pumps are subject to the following sections of 40 CFR Part 60, Subpart IIII.

(1) 40 CFR 60.4200(a);
(2) 40 CFR 60.4205(b);
(3) 40 CFR 60.4205(c);
(4) 40 CFR 60.4206;
(5) 40 CFR 60.4207(a);
(6) 40 CFR 60.4207(b);
(7) 40 CFR 60.4208(a);
(8) 40 CFR 60.4208(b);
(9) 40 CFR 60.4208(g);
(10) 40 CFR 60.4209(a);
(11) 40 CFR 60.4211(a);
(12) 40 CFR 60.4211(c);
(13) 40 CFR 60.4211(e);
(14) 40 CFR 60.4212(a);
(15) 40 CFR 60.4212(b);
(16) 40 CFR 60.4212(c);
(17) 40 CFR 60.4214(b);
(18) 40 CFR 60.4218;
(19) 40 CFR 60.4219;
(20) Table 4 to Subpart IIII of Part 60 - Emission Standard for Stationary Fire Pump Engines;
(21) Table 5 to Subpart IIII of Part 60 - Labeling and Recordkeeping Requirements for New Stationary Emergency Engines;

(22) Table 6 to Subpart IIII of Part 60 - Optional 3-Mode Test Cycle for Stationary Fire Pump Engines; and
(23) Table 8 to Subpart IIII of Part 60 - Applicability of General Provisions to Subpart III.

(p) The source is subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63 Subpart ZZZZ). These Standards apply to new stationary reciprocating internal combusting engines (RICE) and are located at facilities that are area source of HAPs. The specific facilities subject to this rule include the following.

These emissiosn units are subject to the following portions of Subpart ZZZZ:

(a) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, to be permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, emergency diesel fired generator is considered a new affected source.].

(b) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, to be permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, emergency diesel fired generator is considered a new affected source.].

The emergency generator and the firewater pumps are subject to the following sections of 40 CFR Part 63, Subpart ZZZZ.

(1) 40 CFR 63.6590(c)(1).

Pursuant to 40 CFR 63.6665, the two (2) emergency diesel generators and the three (3) firewater pump diesel engines do not have to meet the requirements of 40 CRF 63, Subpart A (General Provisions), since they are considered new stationary RICE located at an area source of HAP emissions.

(q) The source is not a major source of HAPs and is not subject to any of the major source MACT standards under 40 CFR Part 63. However, in the context of the BACT determination for this source, the substantive requirements of 40 CFR 63 Subpart H, addressing equipment leaks, apply to the components listed under 40 CFR 63.160(a) that are in service at the facility for the following process streams: methanol streams, propylene streams, and product SNG streams. The same Subpart H requirements apply to any leaks of SO2 in the Wet Sulfuric Acid unit piping between the combustor and oxidation reactor, beginning with the connector at the combustor and ending with the connector at the oxidation reactor, except that references in the regulations to methane or VOCs will instead be applied to the pollutant SO2.

The following standards will apply to the components subject to this permit requirement:

1. 40 CFR 63.161;
2. 40 CFR 63.162(a);
3. 40 CFR 63.162(c);
4. 40 CFR 63.162(d);
5. 40 CFR 63.162(f);
6. 40 CFR 63.162(g);
7. 40 CFR 63.162(h);
8. 40 CFR 63.163;
9. 40 CFR 63.164;

10. 40 CFR 63.165;
11. 40 CFR 63.166;
12. 40 CFR 63.167;
13. 40 CFR 63.168;
14. 40 CFR 63.169;
15. 40 CFR 63.170;
16. 40 CFR 63.171;
17. 40 CFR 63.172;
18. 40 CFR 63.173; and
19. 40 CFR 63.174.

The alternative quality improvement program for valves under 40 CFR 63.175 and pumps under 40 CFR 63.176 may be used in lieu of the specified requirements of 40 CFR 63.168 and 40 CFR 63.163. The source may apply any alternative method approved by the EPA Administrator under 40 CFR 63.177(e) with written notification to IDEM 30 days in advance of the use of the alternative method. That notification shall include a copy of the EPA approval of the alternative method and an indication of where at the plant the alternative will be applied.

The test methods and procedures used shall be those delineated under 40 CFR 63.180. For the SO2 monitoring of the components in the Wet Sulfuric Acid (WSA), references to methane or VOCs in 40 CFR 63.180 or 40 CFR 60 Appendix A, Method 21 shall be applied instead to the pollutant SO2. If a monitor is used that has a range lower than the defined leak rate, then any reading within 90% of the monitor's range shall be treated as a leak.

The Greenhouse Gases BACT determination for this source, shall be to monitor monthly seals of the CO2 product compressors using audio/visual methods. Any leakage determined by audio/visual or other inspection shall be repaired within the time frames specified in 40 CFR 63.164 (g) except as provided by 63.171 and Recordkeeping shall conform to the provisions of 40 CFR 63.181.

(r) **326 IAC 24 Clean Air Interstate Rule (CAIR)**
The Clean Air Interstate Rule (CAIR) is not applicable to any source at the IG facility. CAIR applies to fossil-fuel fired boilers serving a generator with a nameplate capacity of more than 25 MW and producing electricity for sale. The Auxiliary Boilers (EU-05A/B) are fossil-fuel fired boilers serving a generator. However, pursuant to 326 IAC 24-1(b)(1)(B) the CAIR does not apply to a boiler serving a generator that supplies, in any calendar year, less than 1/3 of the unit's potential electric output capacity or 219,000 MW-hours (25 MW), whichever is greater, to any utility power distribution system for sale. Electricity produced by the Indiana Gasification facility is intended to balance the energy requirements of the facility. This electricity will normally be produced from process generated steam in a steam turbine generator, and any excess that is distributed for sale will not exceed 1/3 of the potential generation. Therefore, the auxiliary boilers, identified as EU-05A and EU-05B are not subject to the requirements of 326 IAC 24.

(s) **40 CFR Part 72-78 Acid Rain Program**
326 IAC 21 incorporates by reference the provisions of 40 CFR 72 through 40 CFR 78 for the purposes of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act and to incorporate monitoring, record keeping, and reporting requirements for nitrogen oxide and sulfur dioxide emissions to demonstrate compliance with nitrogen oxides and sulfur dioxide emission reduction requirements. This source is not subject to the requirements of 326 IAC 21 because it does not sell greater than 1/3 its generated electric. This regulation applies to electric utility generating units that supply greater than 1/3 their potential electrical output and greater than 219,000 MWe-hrs (25MW) actual electrical output on an annual basis to any utility power distribution system for sale. Therefore, the auxiliary boilers, identified as EU-05A and EU-05B are not subject to the requirements of 326 IAC 21.

(t) **40 CFR 68 Chemical Accident Prevention Provisions**
Chemical accident prevention provisions (Risk Management Plans - RMP) are applicable to the stationary sources that have more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115. Compounds present on site which are RMP regulated pollutants includes ammonia, methane and hydrogen sulfide. However, none are present in concentrations or total quantities which trigger RMP applicability. Indiana Gasification, LLC will use aqueous ammonia, however its concentration is less than 20% ammonia – and is therefore is not hazardous enough to be regulated per RMP regulations. Methane, the major product of the facility, is not present in any process greater than the RMP threshold quantity of 10,000 lbs. Hydrogen sulfide will be present in the process, but is present in most processes in concentrations less than 1% (H_2S is not RMP regulated below this concentration.) The total quantity of H2S in processes where it is present less than 1.0% concentration is below the RMP threshold quantity of 10,000 lbs.

State Rule Applicability Determination

326 IAC 2-2 (Prevention of Significant Deterioration)
This new stationary source is one of the 28 listed source categories and has potential to emit of at least one regulated pollutant greater than 100 tons per year. This source is a major source pursuant to 326 IAC 2-2 (PSD).

326 IAC 2-2-3 (PSD BACT: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the source shall be as follows:

Syngas Hydrocarbon Flare, identified as (EU-001):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce PM, PM10 and PM2.5 emissions during startups, shutdowns and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. Comply with the following flare best practices:

a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.

b. Flares shall be operated with a flame present at all times.

c. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

C. The Syngas Hydrocarbon Flare PM/PM_{10} emissions shall not exceed 3.21 lb/hour during startup or shutdown, based on a 3-hour average.

D. The Syngas Hydrocarbon Flare $PM_{2.5}$ emissions shall not exceed 3.01 lb/hour during startup or shutdown, based on a 3-hour average.

(2) The CO emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce CO emissions during startups, shutdowns and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The Permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. Comply with the following flare best practices:

a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.

b. Flares shall be operated with a flame present at all times.

c. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

C. The Syngas Hydrocarbon Flare CO emissions shall not exceed 172.4 lb/hour during startup or shutdown based on a 3 hour average.

(3) The SO_2 emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce SO2 emissions during startups, shutdowns, and other flaring events.

The permittee will use methanol, rather than coal or pet coke, as the feedstock in each gasifier during startup conditions requiring syngas flaring, thereby reducing emissions of sulfur dioxide at the syngas hydrocarbon flare.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented

The SO2 emissions from the Syngas Hydrocarbon Flare during a shutdown event shall not exceed 85.21 lb/hr based on a 3-hour average and shall not exceed 255.6 lb per 24 hours. The SO2 emissions from the Syngas Hydrocarbon Flare shall not exceed 0.35 lb/hour during startup, based on a 3 hour average.

(4) The NOx emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce NOx emissions during startups, shutdowns, and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

In addition, the permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. The Syngas Hydrocarbon Flare NOx emissions shall not exceed 43.09 lb/hour during startup or shutdown based on a 3 hour average.

(5) The GHGs emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce GHG emissions during startups, shutdowns, and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

In addition, the permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Acid Gas Flare, identified as (EU-002):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. Comply with the following flare best practices:

a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
b. Flares shall be operated with a flame present at all times.
c. Flares shall be continuously monitored to assure the presence of a pilot flare with a thermocouple, infrared monitor, or other approved device.

(2) The CO emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

A The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B Comply with the following flare best practices:
a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
b. Flares shall be operated with a flame present at all times.
c. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(3) The SO_2 emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

(4) The NOx emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

B. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

(5) The GHG emissions from the Acid Gas Flare, identified as (EU-002) shall be:

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Auxiliary Boilers, identified as (EU-005 A and B):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0075 lb per MMBtu and only natural gas or SNG shall be used.

(2) The CO emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.036 lb/MMBtu based on a 3 - hour average and good combustion practices shall be used.

(3) The SO_2 emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0006 lb/MMBtu and only natural gas or SNG shall be used.

(4) The NOx emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0125 lb/MMBtu based on a 24-hour block daily average basis and shall use Ultra Low NOx burners with FGR.

(5) The GHGs BACT for the Auxiliary Boilers shall be as follows:

(a) Use of natural gas or SNG;

(b) Energy efficient boiler design (utilizing an economizer, condensate recovery, inlet air controls and blowdown heat recovery.)

(c) Boiler designed for 81% thermal efficiency (HHV).

(d) The total CO_2 emissions from the auxiliary boilers shall not exceed 88,167 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Acid Gas Recovery Unit Vents, identified as (EU-007 A and B):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from operation of the AGR Regenerative Thermal Oxidizers (C-007A/B) shall not exceed 0.29 pounds per hour, each and shall use good combustion practices. Only natural gas or SNG shall be used in the AGR Regenerative Thermal Oxidizers (C-007A/B).

(2) The CO emissions shall be controlled by the use of regenerative thermal oxidizer (RTO) and the CO emissions shall not exceed 48 pounds per hour for the Acid Gas Removal Unit Vents (EU-007A/B), each, based on a 3-hour average.

(3) The SO_2 emissions shall be reduced by the use of a Rectisol process and the SO_2 emissions shall not exceed 3.17 pounds per hour for each Acid Gas Removal Unit Vent (EU-007A/B), based on a 3-hour average.

(4) The NOx emissions from the Acid Gas Removal Unit Vents (EU-007A/B) shall be controlled by Low NOx Performance with natural gas injection and the NOx emissions shall not exceed 1.98 pounds per hour from each AGR/RTO unit based on a 3-hour average.

(5) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents operation shall be limited as follows:

(A) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 4,690,000 tons of CO_2 during the first 12 months of operation.

(B) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 6,430,000 tons of CO_2 during the second 12 months of operation.

(C) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 1, 290,000 tons of CO_2 during the third 12 months of operation.

(D) Thereafter, the CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 1,290,000 tons CO_2 per twelve (12) consecutive month period with compliance determined at the end of each month.

Gasifier Preheat Burners, identified as (EU-008 A - E):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.0007 lb /MMBtu and shall use only natural gas or SNG.

(2) The CO emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.056 lb CO/MMBtu and shall use good combustion practices.

(3) The SO_2 emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall be not exceed 0.0006 lb SO_2/MMBtu and shall use natural gas or SNG.

(4) The NOx emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.10 lb NOx /MMBtu and shall use good combustion practices.

(5) The GHGs BACT for the Gasifier Preheat Burners shall be as follows:

A. The use of good engineering design; and

B. The use of natural gas or SNG.

C. The CO_2 emissions from the Gasifier Preheater Burners shall not exceed 6,438 tons CO_2 per twelve (12) consecutive month period, with compliance determined at the end of each month.

Emergency Generators, identified as (EU-009 A and B):

The BACT for the Emergency generator has been established as follows:

(1) NOx: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(2) CO: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(3) PM/PM10/PM2.5: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation;

(4) SO_2: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation; and

(5) Each emergency generator shall not exceed 52 hours per year of non-emergency operation, each.

(6) The total CO_2 emissions from the emergency engines (EU-009A/B and EU-010A/B/C) shall not exceed 84 tons CO_2 per twelve (12) consecutive month period from non-emergency operation, with compliance determined at the end of each month.

Firewater Pump Engines, identified as (EU-010 A - C):

The BACT for the firewater pump engines has been established as follows:

(1) NOx: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(2) CO: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(3) PM, PM_{10} and $PM_{2.5}$: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation;

(4) SO_2: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation; and

(5) Each firewater pumps shall not exceed 52 hours per year of non-emergency operation, each.

Process Area Solid Feedstock Conveying, storage and feedbin (EU-011 A and B):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B) shall be limited through a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Incoming Solid Feedstock Material Handling System - Barge Unloading (EU-012A):

The PM, PM_{10} and $PM_{2.5}$ emissions from the barge unloading to hopper transfer point (EU-012A) operation shall be controlled by a wet suppression with a control efficiency of 90%.

Railcar Unloading to Rail Hoppers (EU-012G/H):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the railcar unloading to rail hoppers shall be controlled by a wet dust extraction system or baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Barge Unloading from Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Barge Unloading from the Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F) shall be controlled by a wet dust extraction system or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Rail Hoppers Unloading to the Belts (EU-012I-J) and Rail Conveyor Belt to the Stacker (EU-012K):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a wet dust extraction system or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Stacker Belt to the Radial Stacker (EU-012 L- M):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Stacker Belts to the Radial Stacker shall be controlled by a wet dust extraction system or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers (EU-012R-S); Classification towers (EU-012T-U); and Classification tower to a day bin (EU-012V):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a wet dust extraction system or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Radial Stacker to the Pile (EU-012 N-O):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a Telescoping chute with dust collection.

(2) The PM and PM_{10} emissions shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ emissions shall not exceed 0.0015 gr/dscf.

Storage Pile (EU-012W/X):

The PM, PM_{10} and $PM_{2.5}$ emissions from the Storage Piles (EU-012W/X) operation shall be controlled by wet suppression with pile compaction with a control efficiency of 90 %.

Dozer Activity (EU-012P/Q):

The PM, PM_{10} and $PM_{2.5}$ emissions from the Dozer Activities (EU-012P/Q) operation shall be controlled by wet suppression with pile compaction with a control efficiency of 90 %.

Truck/rail conveyor transfer tower (EU-012Y); truck stations unloading to a truck hopper (EU-012AB-AC); and truck hopper unloading to the conveyor Belts (EU-012AA):

(1) An enclosed vent to a wet dust extraction system or a baghouse for control of PM, PM_{10} and $PM_{2.5}$ emissions.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Rod Mill Vent (EU-013A-D):

(1) The PM and PM_{10} emissions from each Rod Mill Vents shall not exceed 0.025 pounds per hour based on a 3-hour average.

(2) The $PM_{2.5}$ emissions from each Rod Mill Vent shall not exceed 0.0074 pounds per hour based on a 3-hour average.

ASU Regeneration Vent (EU-017A and B):

(1) The PM and PM_{10} emissions from each Air Separation Unit (ASU) shall not exceed 0.026 pounds per hour based on a daily average.

(2) The $PM_{2.5}$ emissions from the Air Separation Unit (ASU) shall not exceed 0.009 pounds per hour based on a daily average.

Wet Sulfuric Acid Plants (EU-015 A and B):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a high Efficiency Mist Eliminator and H_2O_2 scrubber and the PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.15 pounds per ton of acid produced and 5 lb/hour, each, based on a 3-hour average.

(2) The H_2SO_4 emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a high Efficiency Mist Eliminator and H_2O_2 scrubber and the H_2SO_4 emissions shall not exceed 0.15 pounds per ton of acid produced and 5 lb/hour, each, based on a 3-hour average.

(3) The CO emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall not exceed 18.7 pounds per hour, each based on a 3-hour average.

(4) The SO_2 emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a peroxide scrubber, the SO_2 emissions shall not exceed 0.25 lb/ton acid produced and 8.3 lbs SO2 per hour, each based on a 24-hour block daily average.

(5) The NOx emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be limited by the use of a selective catalytic reduction (SCR) when the flow to the SCR is at or above a temperature of 750 degrees F and the NOx emissions shall not exceed 10.2 pounds per hour NOx based on a 24-hour block daily average for each Wet Sulfuric Acid unit.

(6) The CO_2 emissions from the Wet Sulfuric Acid Plant operation shall not exceed 474,000 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

ASU and Main Cooling Tower (EU-016A and 016B):

The PM, PM_{10} and $PM_{2.5}$ emissions from the ASU Cooling Tower (EU-016A) and the Main Cooling Tower (EU-016B) shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005% and total dissolved solids shall not exceed 1500 ppm based on a daily average.

Sulfuric Acid Tanks (EU-027A - F):

The H_2SO_4 emissions from the Sulfuric Acid tanks shall be limited by the use of a fixed roof tank and submerged fill.

ZLD Spray Dryer (EU-032):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Zero Liquid Discharge (ZLD) spray dryer shall be controlled by a fabric filter baghouse and the PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed a 0.005 gr/dscf based on a 3 hour average.

(2) The CO emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall not exceed 0.036 lb/MMBtu and shall use good combustion practices.

(3) The SO_2 emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall be limited through the use of natural gas or SNG.

(4) The NOx emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall not exceed 0.035 lb/MMBtu and shall use a Low NOx Burner (LNB).

(5) The GHGs BACT for the Zero Liquid Discharge (ZLD) Spray Dryer shall be as follows:

A. The CO_2 BACT for the Zero Liquid Discharge (ZLD) Spray Dryer shall be the use of good engineering design and the use of natural gas or SNG.

B. The CO_2 emissions from the ZLD Spray Dryer shall not exceed 2,884 tons CO_2 per twelve (12) consecutive month period, with compliance determined at the end of each month.

Fugitive Leaks from piping (FUG & FUG-WSA):

(1) The BACT for fugitive leaks of CO and H_2SO_4 is no-controls.

(2) The BACT for the fugitive leaks of SO_2 in the WSA is the use of a Leak Detection and Repair (LDAR) program.

(3) The BACT for fugitive GHG emissions is the use of a leak detection and repair (LDAR) program for the natural gas and SNG piping and weekly audio/visual inspection of the CO_2 compressors while they are in operation in any week in which there are at least twenty-four (24) hours of operation of the CO_2 compressor to be inspected.

Fugitive Dust From Paved Roads (FUG-ROAD):

The PM, PM_{10} and $PM_{2.5}$ emissions from the paved road (FUG-ROAD) shall be controlled by 90 % by the use of;

(1) Paving all plant haul roads,
(2) Use of wet or chemical suppression
(3) Prompt cleanup of any spilled materials.

Front -end Loader Slag Handling (EU-034A) and Vehicle Dust on Slag Pile (EU-034C):

The PM, PM_{10} and $PM_{2.5}$ emissions from the Front-end Loader Slag Handling (EU-034A) and Vehicle Dust on Slag Pile (EU-034C) shall be controlled by a Wet Suppression or Chemical suppression with 90% control efficiency.

Electric Circuit Breaker (FUG-SF6):

The GHGs BACT for the Electrical Circuit Breaker (FUG-SF6) shall be the use of fully enclosed pressurized SF_6 circuit breakers with leak detection (low pressure alarm).

Hazardous Air Pollutants (HAPs) Minor Limits
The source has the uncontrolled potential to emit greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs, therefore:

The emission units shall be limited as follows:

(a) The Acid Gas Recovery Units, identified as EU-007A/B, Methanol emissions shall be limited to less than nine (9.0) tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The Acid Gas recovery Units, identified as EU-007A/B, combined Hazardous Air Pollutants (HAPs) emissions shall be limited to less than 22.5 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(c) The methanol emissions from the AGRs shall be calculated by the following equation:

Methanol emissions = Vent Flow x Methanol Conc. x (1 – Control Effic.)

Where:

Vent Flow = Total AGR vent flow to the thermal oxidizers (million SCF/period) to be monitored continuously by the Permittee.

Methanol Conc. = Methanol Concentration of the inlet to the thermal oxidizer (lbs methanol/million SCF of vent gas), as determined in the most recent stack test of the oxidizer. Until the initial testing is performed, the engineering estimate of 12.7 lbs methanol/million SCF shall be used.

Control Effic. = The control efficiency of the Regenerative Thermal Oxidizer as determined by stack test. Until the initial stack test is performed, the engineering estimate of 99% control shall be used.

(d) The Permittee shall operate a carbon adsorber on the ZLD Inert Gas Vent. The carbon adsorber shall be used at all times the ZLD inert gas vent is in operation except during carbon adsorber maintenance, repair or carbon replacement. The system shall be designed with a carbon replacement interval of no less than once per year (based on maximum design flow rate and mercury concentration).

Compliance with the above limits and requirements and combined with the potential to emit HAP emissions from all other emission units will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.

Operating Restrictions during Gasifier Startup Flaring
During startup flaring of the gasifiers, the Permittee shall not test an emergency engine (EU-009A/B and EU-010A/B/C). This operating restriction shall be applicable beginning when a starting up gasifier first begins to flare generated syngas and ends when the generated syngas begins diversion from the flare to the downstream AGR/WSA trains.

Alternative Emissions Limitation during Gasifier Startup Flaring
(a) During startup flaring of the gasifiers, NOx emissions from the AGR units (EU-007A/B) shall be limited to 2.97 lbs/hr combined from both AGR units (EU-007A/B) and shall be applicable beginning when a starting up gasifier first begins to flare generated syngas and ends when the generated syngas begins diversion from the flare to the downstream AGR/WSA trains.

(b) During startup flaring of the gasifiers, NOx emissions from the WSA units (EU-015A/B) shall be limited to 15.26 lbs/hr combined from both WSA units (EU-015A/B) and shall be applicable beginning when a starting up gasifier first begins to flare generated syngas and ends when the generated syngas begins diversion from the flare to the downstream AGR/WSA trains.

Operational Limits for the auxiliary Boilers
The total throughput of fuel to the two (2) natural gas-fired auxiliary boilers, identified as EU-005A/B, shall be limited to a total firing rate of 1430 billion Btu per twelve (12) consecutive month period, with compliance determined at the end of each month.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The operation of emission units in the plant will emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 1-7 (Actual Stack Height Provisions)
326 IAC 1-7 applies to exhaust stacks with potential particulate or sulfur dioxide emissions of 25 tons per year or more. 326 IAC 1-7-3(a) requires that new stacks meeting these criteria be constructed using either good engineering practice (GEP) or, at least, with a stack height sufficient to insure that emissions will not cause excessive ground level concentrations due to downwash, eddies, or wakes.

Each Regenerative Thermal Oxidizer Vent (EU-07) and each Wet Sulfuric Acid Plant Vent (EU-15) will have potential SO_2 emissions greater than 25 tons per year, so these stacks will be subject to this rule for SO_2. No other stacks at the proposed facility meet the applicability criteria.

326 IAC 2-6 (Emission Reporting)
Since this source is required to have an operating permit under 326 IAC 2-7, Part 70 Permit Program, this source is subject to 326 IAC 2-6 (Emission Reporting). In accordance with the compliance schedule in 326 IAC 2-6-3, an emission statement must be submitted triennially. The first report is due no later than July 1, 2014, and subsequent reports are due every three (3) years thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 5-1 (Opacity Limitations)
This source is subject to the opacity limitations specified in 326 IAC 5-1-2(2).

326 IAC 6-4 (Fugitive Dust Emissions)
The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions).

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)
The source is subject to the requirements of 326 IAC 6-5 because it is a new source of fugitive particulate matter emissions, located anywhere in the state, requiring a permit as set forth in 326 IAC 2, which has not received all the necessary preconstruction approvals before December 13, 1985.

326 IAC 3-5 (Continuous Monitoring of Emissions)
The auxiliary boilers, identified as EU-05A and EU-05B are subject to the monitoring requirements of 326 IAC 3-5 because they are fossil fuel fired steam generators that have a heat input capacity of greater than 100 MMBtu per hour.

(a) Pursuant to 326 IAC 3-5-1(c)(2)(A), a continuous monitoring system for NOx shall be installed, calibrated, maintained, and operated to measure the NOx emissions from the exhaust of the two auxiliary boilers, identified as EU-05A and EU-05B.

(b) Pursuant to 326 IAC 3-5-1(c)(2)(C) and (D), a continuous monitoring system shall be installed, calibrated, maintained, and operated to measure Nitrogen Oxide (NOx) and either O_2 or CO_2 emissions from auxiliary boilers, identified as EU-05A and EU-05B since the boilers are subject to NOx monitoring under 40 CFR 60.

(c) Pursuant to 326 IAC 3-5(c) (2) (A) (i) the Auxiliary Boiler are exempts from continuous opacity monitoring because it burns only gaseous fuels. SO_2 monitoring is not required because the boiler will not be subject to SO_2 monitoring under 40 CFR 60 and will not have SO_2 air pollution control equipment.

(d) The requirements of 326 IAC 3-5 also applies to "sulfuric acid plants or production facilities of greater than 300 tons per day acid production capacity". 326 IAC does not contain a definition of "sulfuric acid plants or production facilities", other than in 40 CFR 60 Subpart H incorporated by reference at 326 IAC 12 which exempts processes with the primary purpose of reducing atmospheric emissions of sulfur compounds.

The IG Sulfuric Acid Plants are facilities where the conversion to sulfuric acid is performed primarily as a means of reducing atmospheric emissions of SO_2 or other sulfuric compounds. Since the Indiana Gasification sulfuric acid plants do not meet the definition of sulfuric acid production unit in Subpart H, the sulfuric acid plants are not be subject to the requirements of 326 IAC 3-5.

326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating)
(a) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from the auxilliary boilers, identified as EU-05A and EU-05B shall not exceed 0.19 pounds per million Btu heat input (lb/MMBtu), each. This limitation was calculated using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

Where:

Q = total source heat input capacity (MMBtu/hr).
For these units, Q = 816.0 MMBtu/hr.

However, 326 IAC 6-2-4 (h) states that if a limitation established by this rule is inconsistent with a limitation required by the permit regulations, then the permit regulation limit will prevail. Since the BACT emissions limit is significantly more stringent than the above calculated limit, compliance with the BACT particulate matter limits renders the above rule (326 IAC 6-2-4) not applicable to these auxiliary boilers.

(b) The gasifier startup burners, identified as EU-08 and WSA preheat burners, identified as EU-15 are process heaters and not indirect heat exchangers pursuant to 40 CFR 60 Subpart Dc, therefore, these emission units are not subject to the requirements of 326 IAC 6-2.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)

(a) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the Process Area Solid Feedstock Handling Operations (EU-11A/B) and Wind Erosion from the coal/coke piles (EU-12W/X) shall not exceed 67.2 pounds per hour when operating at a process weight rate of 430 tons per hour. The pound per hour limitation was calculated with the following equation:

Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 55.0\ P^{0.11} - 40$ where E = rate of emission in pounds per hour; and
P = process weight rate in tons per hour

The BACT limit for these emission units are much more stringent. Therefore, pursuant to 326 IAC 6-3-1(b), these emission units are exempt from the requirements of 326 IAC 6-3-2.

(b) Pursuant to 326 IAC 6-3-1(b)(14), EU-13 Rod Mill Air Eductors and EU-17 ASU Sieve Regeneration are exempt from this rule because potential PM emissions are less than 0.551 lb per hour.

(c) Pursuant to 326 IAC 6-3-1(b)(14), the noncontact cooling tower systems, trivial activities as defined at 326 IAC 2-7-1(40), processes with potential emissions less than 0.551 lb/hr, and where a particulate limit established under BACT or another rule is more stringent are exempt from this rule.

326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations)

(a) This Acid gas removal (AGR) unit and the Wet sulfuric acid (WSA) are subject to the requirements of 326 IAC 7-1.1-2 because the emission units have potential to emit greater than 25 tons of SO_2 per year, each. However, pursuant to this rule, there are no specific SO_2 emission limitations for the combustion of natural gas. Therefore, the requirements of 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations) are not applicable to the Acid gas removal (AGR) units and the Wet sulfuric acid (WSA) at this source.

(b) All other emission units are not subject to the requirements of 326 IAC 7-1.1-2 because they have the potential to emit less than 25 tons of SO_2 per year. Therefore, the requirements of 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations) are not applicable to any emission unit at this source.

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)

(a) This rule requires that new facilities (as of January 1, 1980), which have potential VOC emissions of 25 tons or more per year, located anywhere in the state, which are not otherwise regulated by other provisions of 326 IAC 8, shall reduce VOC emissions using Best Available Control Technology (BACT). The uncontrolled VOC emissions from the Acid Gas Recovery Unit Vents, identified as EU-007A/B are greater than 25 tons per year.

Pursuant to 326 IAC 8-1-6, IDEM has established BACT for VOC for the Acid Gas Recovery Unit Vents, identified as EU-007A/B as follows:

The VOC emissions from the Acid Gas Recovery Unit vents (EU-007A/B) shall be controlled through the use of a Regenerative Thermal Oxidizer on each vent and the VOC emissions for each vent shall not exceed 1.05 pounds per hour based on a 3-hour average.

(b) The uncontrolled VOC emissions from all other emission units are less than 25 tons per year, therefore, all other emission units at this source are not subject to the requirements of 326 IAC 8-1-6 (New Facilities; General Reduction Requirements).

326 IAC 8-4-6 (Gasoline Dispensing Facilities)
Pursuant to 326 IAC 8-4-1(f) and 326 IAC 8-4-6 the requirements of this rule do not apply to the gasoline storage tank at a gasoline dispensing facility, though this facility is constructed after July 1, 1989 the facility has a monthly gasoline throughput of less than ten thousand (10,000) gallons per month.

326 IAC 8-9-1 (Volatile Organic Liquid Storage Vessels)
Pursuant 326 IAC 8-9-1(a) this rule only applies to VOL storage vessels located in Clark, Floyd, Lake, or Porter County. This source is located in Spencer County.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
This source is subject to 326 IAC 9-1 because it is a stationary source of CO emissions commencing operation after March 21, 1972 and has CO emissions of more than 100 tons per year. There are no applicable CO emission limits, under this state rule, established for this type of operation.

326 IAC 2-2-4 (Air Quality Analysis Requirements)
Section (4)(a) of this rule, requires that the PSD application shall contain an analysis of ambient air quality in the area that the major stationary source would affect for pollutants that are emitted at major levels or significant amounts. Indiana Gasification LLC has submitted an air quality analysis, which has been evaluated by IDEM's Technical Support and Modeling Section. See details in Appendix C.

NAAQS modeling for the 24-hour time-averaging period for $PM_{2.5}$was conducted and compared to the respective NAAQS limit. For the 24-hour modeling, two scenarios were examined and had to do with feedstock deliveries both by truck or train. These operations cannot occur at the same time due to equipment and logistical constraints. OAQ modeling results are shown in Table 5a. All maximum-modeled concentrations were compared to the respective NAAQS limit. All maximum-modeled concentrations during the five years plus background were not below the NAAQS limit and a culpability analysis was required.

326 IAC 2-2-5 (Air Quality Impact Requirements)
326 IAC 2-2-5(e)(1) of this rule, requires that the air quality impact analysis required by this section shall be conducted in accordance with the following provisions:

(1) Any estimates of ambient air concentrations used in the demonstration processes required by this section shall be based upon the applicable air quality models, data bases, and other requirements specified in 40 CFR Part 51, Appendix W (Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Guideline on Air Quality Models).

(2) Where an air quality impact model specified in the guidelines cited in subdivision (1) is inappropriate, a model may be modified or another model substituted provided that all applicable guidelines are satisfied.

(3) Modifications or substitution of any model may only be done in accordance with guideline documents and with written approval from U.S. EPA and shall be subject to public comment procedures set forth in 326 IAC 2-1.1-6.

Economic Growth
The purpose of the growth analysis is to quantify project associated growth and estimate the air quality impacts from this growth either quantitatively or qualitatively.

It is estimated that approximately 200 additional jobs will be created as a result of the proposed project. Most of the employees will be drawn from surrounding areas. Since the area is predominately rural, it is not expected the growth impacts will cause a violation of the NAAQs or the PSD increment.

Soils and Vegetation Analysis
A list of soil types present in the general area was determined. Soil types include the following: Moderately thick loess over weathered loamy glacial till, discontinuous loess over weathered sandstone and shale, discontinuous loess over weathered limestone and shale.

Due to the agricultural nature of the land, crops in the Spencer County area consist mainly of corn, sorghum, wheat, soybeans, and oats (2002 Agricultural Census for Spencer County). The maximum modeled concentrations for Indiana Gasification, LLC are well below the threshold limits necessary to have adverse impacts on the surrounding vegetation such as autumn bent, nimblewill, barnyard grass, bishop's cap and horsetail, and milkweed (Flora of Indiana – Charles Deam). Livestock in Spencer County consist mainly of hogs, cattle, and sheep (2002 Agricultural Census for Spencer County) and will not be adversely impacted from the facility. Trees in the area are mainly hardwoods. These are hardy trees and no significant adverse impacts are expected due to modeled concentrations.

Federal and State Endangered Species Analysis
Federal and state endangered species are listed by the U.S. Fish and Wildlife Service; Division of Endangered Species for Indiana, and includes 5 amphibians, 27 birds, 10 fishes, 6 mammals, 15 mollusks, and 15 reptiles. Of the federal and state endangered species on the list, 1 reptile, 3 mollusks, 1 fish, 4 birds, and 2 mammals have habitat within Spencer County. The mollusks, fish, amphibians, and certain species of birds and mammals are found along rivers and lakes while the other species of birds and mammals are found in forested areas. The facility is not expected to have any additional adverse effects on the habitats of the species than what has already occurred from the industrial, farming, and residential activities in the area.

Federal and state endangered plants are listed by the U.S. Fish and Wildlife Service, Division of Endangered Species for Indiana. At this time 8 state endangered plant species are found in Spencer County. The endangered plants do not thrive in industrialized and residential areas. The facility is not expected to adversely affect any plant on the endangered species list.

326 IAC 2-2-6 (Increment Consumption Requirements)
326 IAC 2-2-6(a) requires that any demonstration under section 5 of this rule shall demonstrate that increased emissions caused by the proposed major stationary source will not exceed eighty percent (80%) of the available maximum allowable increases (MAI) over the baseline concentration of sulfur dioxide, particulate matter, and nitrogen dioxide indicated in subsection (b)(1) of this rule.

326 IAC 2-2-7 (Additional Analysis, Requirements)
326 IAC 2-2-7(a) requires an analysis of the impairment to visibility, soils and vegetation. An analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the source. See detailed analysis in Appendix C.

326 IAC 2-2-8 (Source Obligation)
(1) Pursuant to 2-2-8(1), approval to construct, shall become invalid if construction is not commenced within eighteen (18) months after receipt of the approval, if construction is

discontinued for a period of eighteen (18) months or more, or if construction is not completed within a reasonable time.

(2) Approval for construction shall not relieve the Permittee of the responsibility to comply fully with applicable provisions of the state implementation plan and any other requirements under local, state, or federal law.

326IAC 2-2-10 (Source Information)
The Permittee has submitted all information necessary to perform an analysis or make the determination required under this rule.

326 IAC 2-2-12 (Permit Rescission)
The permit issued under this rule shall remain in effect unless and until it is rescinded, modified, revoked, or it expires in accordance with 326 IAC 2-1.1-9.5 or section 8 of this rule.

326 IAC 24 Clean Air Interstate Rule (CAIR)
The Clean Air Interstate Rule (CAIR) is not applicable to any source at the IG facility. CAIR applies to fossil-fuel fired boilers serving a generator with a nameplate capacity of more than 25 MW and producing electricity for sale. The Auxiliary Boilers (EU-05A/B) are fossil-fuel fired boilers serving a generator. However, pursuant to 326 IAC 24-1(b)(1)(B) the CAIR does not apply to a boiler serving a generator that supplies, in any calendar year, less than 1/3 of the unit's potential electric output capacity or 219,000 MW-hours (25 MW), whichever is greater, to any utility power distribution system for sale. Electricity produced by the Indiana Gasification facility is intended to balance the energy requirements of the facility. This electricity will normally be produced from process generated steam in a steam turbine generator, and any excess that is distributed for sale will not exceed 1/3 of the potential generation. Therefore, the auxiliary boilers, identified as EU-05A and EU-05B are not subject to the requirements of 326 IAC 24.

326 IAC 21 Acid Deposition Control
326 IAC 21 incorporates by reference the provisions of 40 CFR 72 through 40 CFR 78 for the purposes of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act and to incorporate monitoring, record keeping, and reporting requirements for nitrogen oxide and sulfur dioxide emissions to demonstrate compliance with nitrogen oxides and sulfur dioxide emission reduction requirements. This source is not subject to the requirements of 326 IAC 21 because it does not sell greater than 1/3 its generated electric. This regulation applies to electric utility generating units that supply greater than 1/3 their potential electrical output and greater than 219,000 MWe-hrs (25MW) actual electrical output on an annual basis to any utility power distribution system for sale. Therefore, the auxiliary boilers, identified as EU-05A and EU-05B are not subject to the requirements of 326 IAC 21.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

The compliance monitoring requirements applicable to this modification are as follows:

Testing Requirements

(a) Testing Requirements

Emission units	Control device	When to test	Pollutants	Frequency of testing	Limit or Requirement
Auxiliary Boiler (A-B) -005	No control	not later than 180 days after initial startup of the first gasifier	CO	one time testing	326 IAC -2-2-3
Auxiliary Boiler (A-B) -005	No control	not later than 180 days after initial startup of the first gasifier	Thermal Efficiency	one time testing	326 IAC -2-2-3
Acid Gas Recovery Unit (A-B) -007	No Control	No later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	NOx	one time testing	326 IAC -2-2-3
Acid Gas Recovery Unit (A-B) -007	Regenerative Thermal Oxidizer	No later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	CO	Every five (5) years	326 IAC -2-2-3
Acid Gas Recovery Unit (007 A-B)	Regenerative Thermal Oxidizer	No later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	VOC	Every five (5) years	326 IAC 8-1-6
Acid Gas Recovery Unit (007 A-B)	Regenerative Thermal Oxidizer	No later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	HAPs (Methanol)	Every five (5) years	HAPs Minor Limit
Process Area Solid Feedstock Handling (Coal/Petcoke) - 011	Baghouse	No later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	PM, PM_{10} and $PM_{2.5}$	Every five (5) years	326 IAC -2-2-3
Incoming Solid Feed stock handling (Coal/petcoke) (B-V, Y-AC) - 012	Dust Extraction, or Baghouse, Telescoping Chute/ Wet Suppression	No later than 180 days after initial startup of the first gasifier	PM, PM_{10} and $PM_{2.5}$	Every five (5) years	326 IAC -2-2-3

Emission units	Control device	When to test	Pollutants	Frequency of testing	Limit or Requirement
Wet Sulfuric Acid Plant (A-B) - 015	Mist eliminator/Peroxide Scrubber	not later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	PM, PM_{10} $PM_{2.5}$ and H_2S0_4	Every five (5) years	326 IAC -2-2-3
Wet Sulfuric Acid Plant (A-B) - 015	No Control	not later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	CO	one time testing	326 IAC -2-2-3
ZLD Spray Dryer	Baghouse	not later than 180 days after initial startup of the fourth gasifier, but not later than 365 days after the initial startup of the first gasifier	PM, PM_{10} and $PM_{2.5}$	Every five (5) years	326 IAC -2-2-3

Stack testing of the ZLD Spray Dryer for NOx emission is not justified because of its small size and low emissions rate. NOx emissions from this source results from combustion of natural gas in a standard gas burner incorporated in the dryer design. The maximum capacity of the burner is only 5.6 MMBtu per hr and NOx emissions are less than one (1) ton per yr. Stack testing this small, uncontrolled source is not required for this unit.

Stack testing the Gasifier Preheat Burners for NOx emissions is not justified because it is technically very difficult and also because the burners are each such small sources. There are five (5) preheat burners, which are used intermittently during gasifier startups and/or to keep a spare gasifier in hot standby. All five burners added together, over the course of a year, average only 12 MMBtu per hr (2.4 MMBtu/hr each) and collectively only emit 5.26 tons per year of NOx. Also, it would be technically very difficult to test these emissions because of the unique process configuration. The burners are used inside of the gasifier vessel to warm it prior to startup. Unlike a conventional heater or boiler, the gasifier vessels are fully enclosed vessels and can't rely on natural draft for combustion air or for venting combustion exhaust. Instead this is accomplished by use of a steam eductor to draw out the combustion exhaust. The steam eductor injects steam directly into the exhaust flow. The resultant vent stream is mostly water vapor, with only a small amount of exhaust. The extremely high moisture content of this vent stream would be technically very difficult to stack test. Because of these difficulties and the small size of these sources, stack testing is not required for this emission unit.

(b) The compliance monitoring requirements applicable to this source are as follows:

Control	Parameter	Frequency	Range/ Value	Excursions and Exceedances	Limit or Requirement
Syngas Hydrocarbon Flare (EU-001)	Flare pilot flame	Continuous	N/A	Response steps	326 IAC 2-2-3
	Total gas flow				
	Visible Emissions	Daily			
Acid Gas Flare (EU-002) (Thermocouple)	Flare pilot flame	Continuous	N/A	Response steps	326 IAC 2-2-3
	Visible Emissions	Daily			
Acid Gas Recovery Unit (A-B) -007 (RTO)	Temperature	Continuous	> 1600 °F		

Control	Parameter	Frequency	Range/ Value	Excursions and Exceedances	Limit or Requirement
Acid Gas Recovery Unit (A-B) -007 (water wash tower)	Water wash flow rate	Continuous	N/A	Response steps	HAPs Minor Limit
Wet Sulfuric Acid Plant (A-B) - 015 (Peroxide Scrubber)	Compliance with the SO_2 emissions limit	Continuous (w/CEM)	8.3 lb/hr each WSA (24 hr average)	Response steps	326 IAC 2-2-3 and 40 CFR 64
Wet Sulfuric Acid Plant (A-B) - 015 (SCR)	Temperature	Continuous when SCR is not operating	N/A	Response steps	326 IAC 2-2-3
Wet Sulfuric Acid Plant (A-B) - 015 (Mist Eliminator/Peroxide Scrubber)	Flow Rate	Daily	N/A	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Pressure Drop		1.0 - 5.0 inches		
Wet Sulfuric Acid Plant (A-B) - 015 (SCR)	compliance with NOx emission limit	Daily	NA	Response steps	326 IAC 2-2-3 and 40 CFR 64
Process Area Solid Feedstock Handling (Coal/Petcoke) - 011 (Baghouse)	Water Pressure Drop	Daily	1.0 to 5.0 inches	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Visible Emissions		Normal-Abnormal		
Incoming Solid Feed stock Radial Stacker (N-O) -012 (Fabric Filters/Telescoping Chute	Water Pressure Drop	Daily	1.0 to 5.0 inches	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Visible Emissions		Normal-Abnormal		
Incoming Solid Feed stock open handling (A,P,Q,W,X) -012 (Wet Suppression)	Visible Emissions	Daily	Normal-Abnormal	Response steps	326 IAC 2-2-3 and 40 CFR 64
Incoming Solid Feed stock enclosed handling (B-M, R-V, Y-AC) EU- 012 Wet Dust Extractor or Baghouse	Water flow rate	Daily	> 1. 5 gpm	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Water Pressure Drop		1.0 to 5.0 inches		
	Visible Emissions		Normal-Abnormal		
Incoming Solid Feed stock enclosed handling (R-S) EU-012 Wet Dust Extractor or Baghouse	Water flow rate	Daily	> 5.0 gpm	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Water Pressure Drop		1.0 to 5.0 inches		
	Visible Emissions		Normal-Abnormal		
ZLD Spray Dryer - 032(Baghouse)	Water Pressure Drop	Daily	1.0 to 5.0 inches	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Visible Emissions		Normal-Abnormal		
Methanol Storage Tank (Condenser)	Refrigerant Temperature	Continuous	< 0°F	Response steps	40 CFR 64
ZLD Vent EU-033 Sulfided Carbon Adsorbent	Pressure Drop	Weekly	N/A	Response steps	HAPs Minor Limit

(c) **Continuous Emission Monitoring System (CEMs) Requirements applicable to this source are as follows:**

Control	Parameter	Frequency	Value	Excursions and Exceedances	Requirement
Auxiliary Boiler (A-B) -005	NOx CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	326 IAC 2-2-3
Wet Sulfuric Acid Plant (A-B) - 015	NOx CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	326 IAC 2-2-3
Wet Sulfuric Acid Plant (A-B) - 015	SO_2 CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	326 IAC 2-2-3
Wet Sulfuric Acid Plant (A-B) - 015	CO_2 CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	326 IAC 2-2-3

Conclusion and Recommendation

The construction and operation of this proposed new source shall be subject to the conditions of the attached proposed Part 70 PSD/New Source Construction and operating permit No.T147-30464-00060. The staff recommends to the Commissioner that this Part 70 PSD/New Source Construction and operating permit be approved.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Josiah Balogun at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) (234-5257) or toll free at 1-800-451-6027 extension (4-5257).

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM's Guide for Citizen Participation and Permit Guide on the Internet at: www.idem.in.gov

SUMMIT POWER

Texas Clean Energy Project

Progress Report

Chris Kirksey, Summit Power Group, Inc.

Midland, Texas • December 8, 2011

Snapshot of TCEP

SUMMIT POWER

- 400 MW "polygen" IGCC project w/ 90% carbon capture
- Siemens gasifiers & 1x1 F-class CCCT w/ high H_2 CT
- Located near Odessa site directly atop Permian Basin
- All components already in commercial use elsewhere; only the integration is new; intended as a reference plant
- Fixed-price, lump sum, turnkey EPC contracts complete
- Siemens & Linde will warrant long-term performance & availability under 15-year O&M Agreement
- 90% carbon capture rate yields ≈ 2.5M std tpy of CO_2; CO_2 emissions only 20 to 30% of a natural gas CCCT's

Update: TCEP is ready

Since last year's conference here in Midland:

- Permitting now complete:
  - Record of Decision from US DOE on 9/27/11 (completes NEPA/EIS process)
  - Air permit issued 12/28/10 (no greenhouse gas emissions limits)
- Off-take agreements now complete:
  - 100% of power sold to CPS Energy for 25 years (executed 12/4/2011)
  - 100% of CO_2 sold for 30 years (three different buyers; market remains strong)
  - 100% of urea sold for 15 years (buyer is a huge fertilizer/chemical company)
- EPC contracts complete & will be signed this month: unique result
  - Siemens, Linde, and SK E&C are the EPC contractors
  - Lump-sum, fixed-price, turnkey EPC contracts (power block + chemical block)
- IRR range looks good for equity investment
- Bank syndicate (led by RBS) formed to obtain necessary debt

Off-take information

- <u>Power sales agreement with CPS Energy (largest U.S. muni utility)</u>:
  - 195 MW of take-or-pay capacity; delivery point is nearby Oncor T-Line
  - Buyer pays fixed cost for capacity + agreed O&M charges for energy
  - Carbon content of power: less than 25% of that from a natural gas CCCT
  - *First time any utility has bought low-carbon power from a commercial-scale carbon capture power plant – a milestone in global environmental history*
- <u>CO_2 sales (for 2.5 million tons per year of CO_2, take-or-pay)</u>:
  - Slightly different pricing formulas in each of three (3) contracts
  - Price is for each Mcf; average price somewhat higher than reported "market"
  - Buyer pays (a) transportation costs, plus (b) increases in compression costs
  - Buyer gets 100% of severance tax and sales tax benefits under HB 469
- <u>Urea prices (all sold to one buyer under take-or-pay contract)</u>:
  - Agreed floor price with agreed formula for sharing market price above floor
  - Excellent market price outlook (plus ability to make liquid fuels in long term)

Status of Financing

SUMMIT
POWER

- DOE $450M award is now vested (can't be "clawed back")
- $313M Sec. 48A investment tax credit also vested via an IRS contract
- TCEP also qualifies for accelerated depreciation (5-year MACRS)
- Well over $1 billion in total tax benefits (TCEP's "fourth product")
- Financial model yields sufficient debt service coverage & returns
- Potential upside for equity investors:
  - Congress can eliminate $157M tax on DOE grant (this is revenue neutral to US)
  - DOE has legal ability to provide more funds & ITC if/as/when available
  - TCEP's carbon credits expected to be saleable; decent prices forecasted
  - TCEP may receive cost-sharing payments from future replica projects
  - Price of oil may exceed $70 per barrel! (The number used by the banks.)

CO_2 sales

- TCEP's captured $CO_2 \approx$ 147,000 Mcf per day in normal operation
- Volume smaller than originally planned because we increased urea
- Russell Martin of Blue Source/Blue Strategies led our sales effort
- Sales negotiations were conducted on non-exclusive basis
- Buyers of this CO_2 will receive two large benefits under HB 469:
  - Oil severance tax cut to 25% (i.e., 50% of normal CO_2/EOR rate)
  - Sales tax exemption for CO_2 transport & injection equipment
- Connection to Kinder-Morgan's nearby Central Basin Pipe Line
- TBEG is in accord with MVA plan that Blue S devised for producers

Coal gasification is real: 5 TCEP-type units in China

SUMMIT POWER

Meanwhile . . .

SUMMIT POWER

- Summit has created Summit Carbon Capture, LLC (SCC)
- SCC will focus on (1) CO_2 capture plants, for (2) EOR, in first instance
- EOR is the current key to CO_2 capture plants; other CCS comes later
- The plants we currently plan include:
  - TCEP “replica” opportunities in Texas, elsewhere in U.S. & abroad
  - Natural gas-fired plants with post-combustion CO_2 capture
  - Surface facilities for underground gasification with CO_2 capture
  - Gasification facilities (without power production) with CO_2 capture
  - Facilities to capture CO_2 directly from the surrounding air
- But: **TCEP comes first!** Construction photos – see ‘em here in 2012!

Overview of the Kemper County and TMEP IGCC Projects Using TRansport Integrated Gasification (TRIG™)

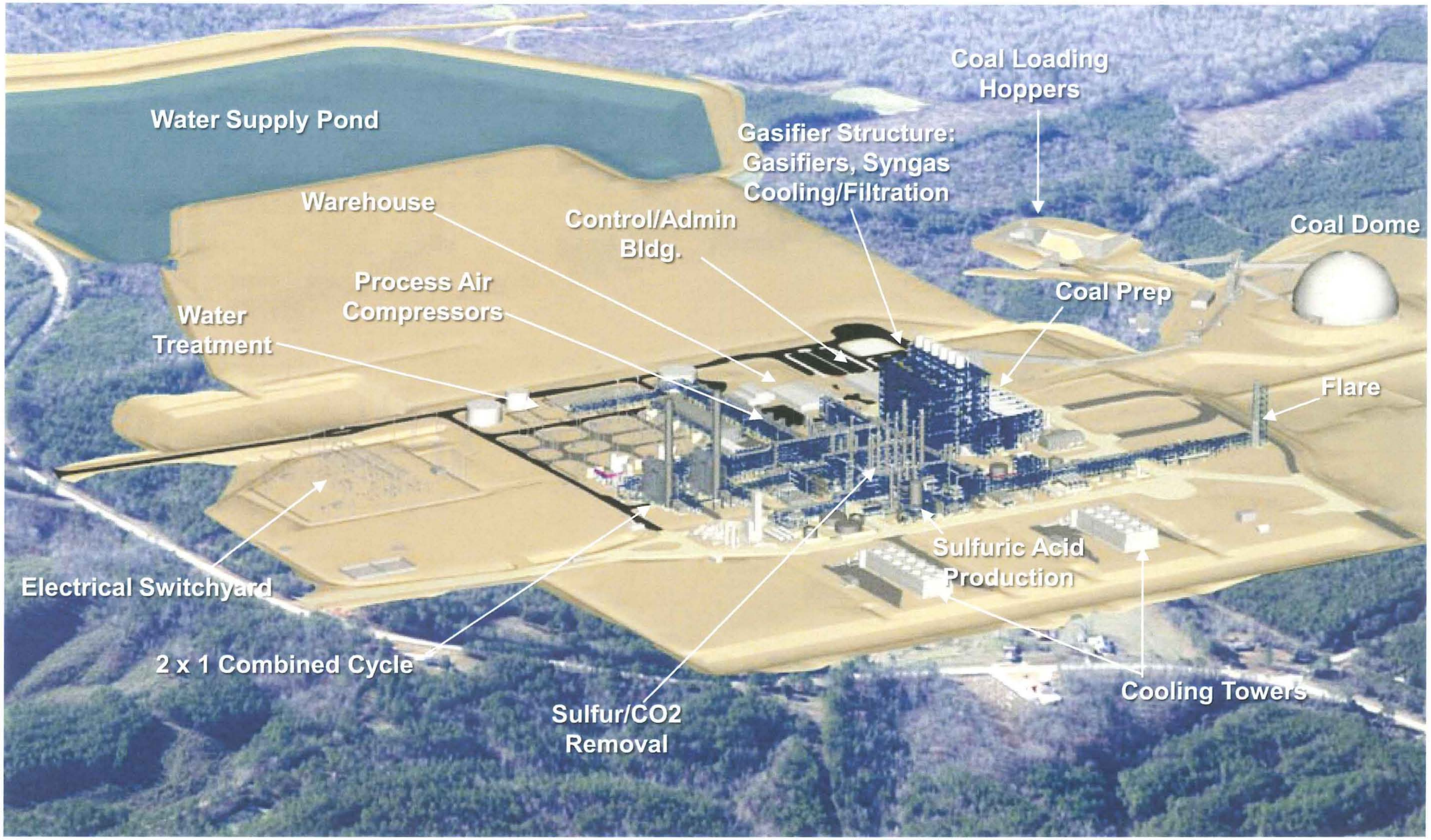
Randall Rush
GM Gasification Technology
Southern Company

2011 Gasification Technology Conference
San Francisco, CA – October 10, 2011

TRIG™
TRANSPORT INTEGRATED GASIFICATION

SOUTHERN COMPANY
Energy to Serve Your World®

Kemper County IGCC



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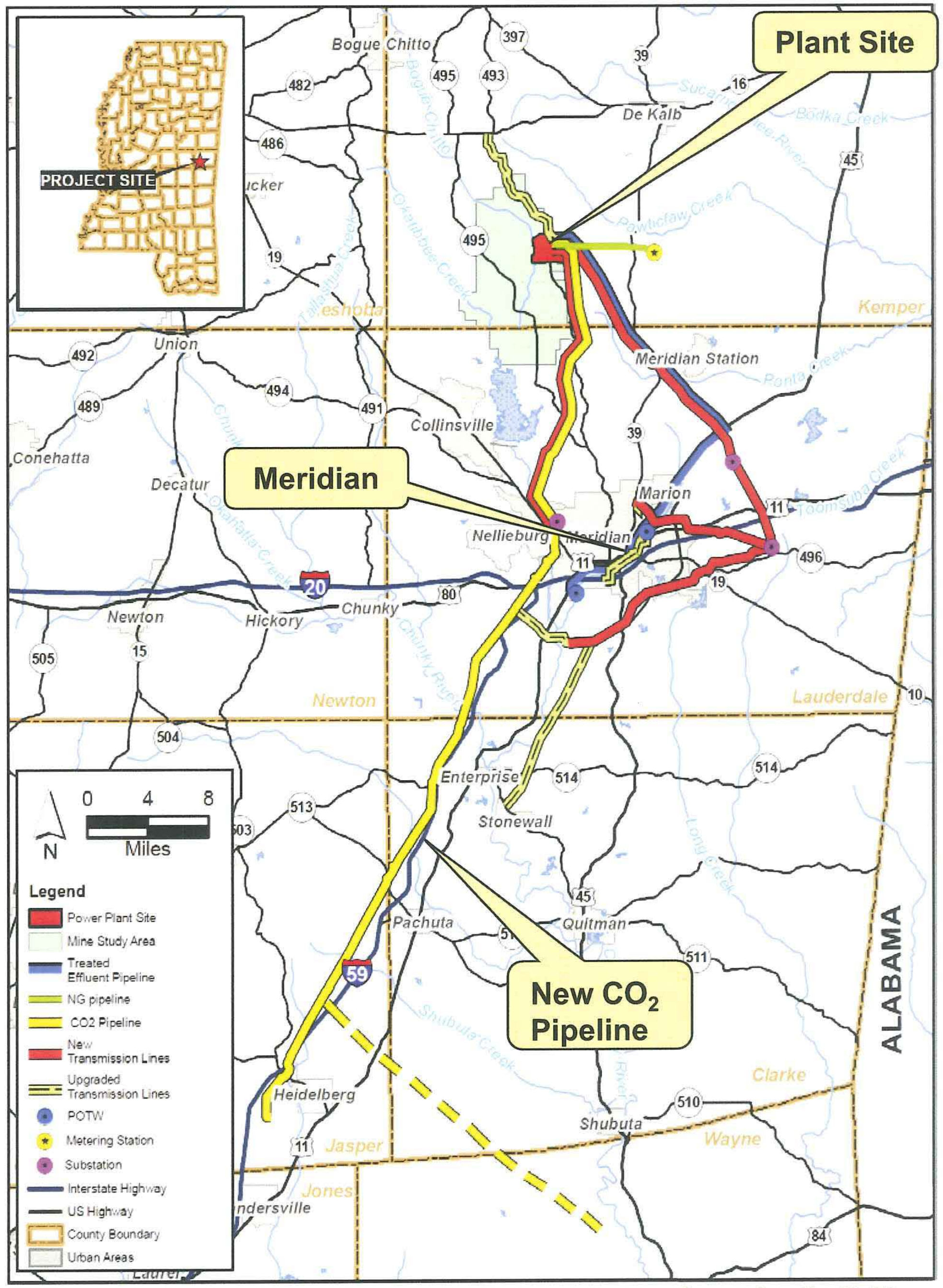
Kemper County IGCC Project Map

- ~70 miles transmission
- ~ 60 miles CO_2 pipeline (for EOR)
- ~5 miles natural gas pipeline
- ~31,000 acre mine site
- ~2,900 acres plant site
- ~ 30 miles treated effluent line



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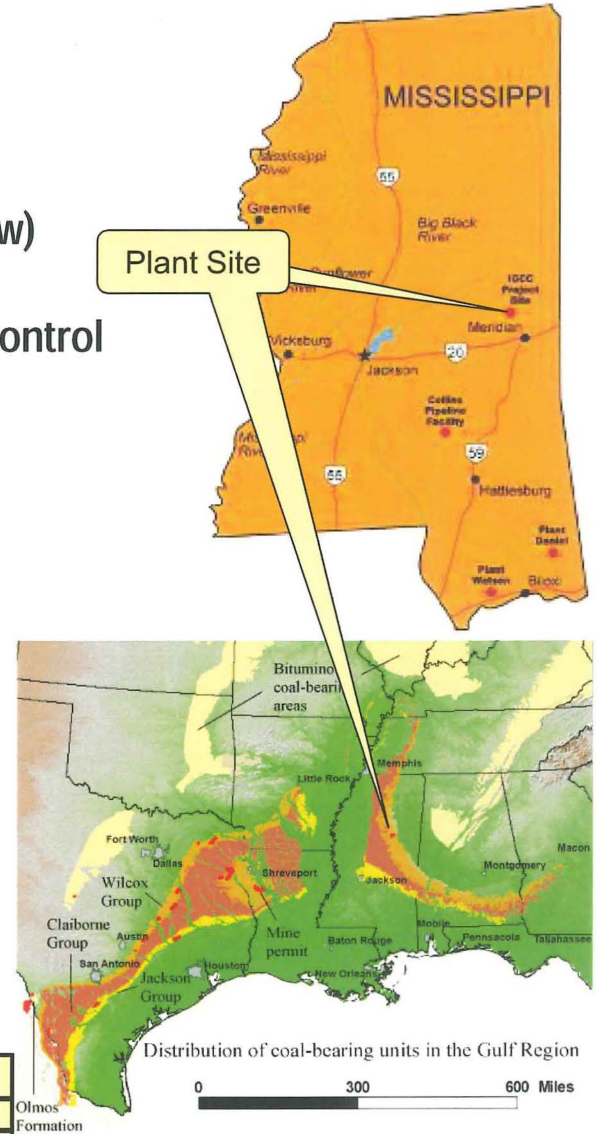
Kemper County IGCC Overview

- 2x1 Integrated Gasification Combined Cycle (IGCC)
  - 2 TRansport Integrated Gasifiers (TRIG™)
  - 2 Siemens SGT6 - 5000F CTs
  - 1 Toshiba Steam Turbine (Tandem Compound Double Flow)
  - 582 MW peak and 524 MW on syngas
  - Heat Rate 11,708 Btu/kWh (29.5% HHV Efficiency w/ CO_2 control and 40+% moisture coal)
  - Selexol for H_2S and CO_2 removal
  - 65+% CO_2 capture (~800 lb/mWh emission rate)
  - Mine Mouth Lignite
- Owner & Operator: Mississippi Power
- Over $2 billion capital investment
- Commercial Operating Date: May 2014
- Use treated effluent from Meridian as makeup water
- Operate with Zero Liquid Discharge (ZLD)
- By-Products (TPY)
  - ~3,000,000 - Carbon dioxide used for EOR
  - ~135,000 - Sulfuric acid
  - ~20,000 - Ammonia



Distribution of coal-bearing units in the Gulf Region

Kemper Lignite Composition				
		Average	Min	Max
Heat Content	btu/lb	5,290	4,765	5,870
Moisture	%	45.5	42	50
Ash	%	12.0	8.6	17
Sulfur	%	1.0	0.35	1.7

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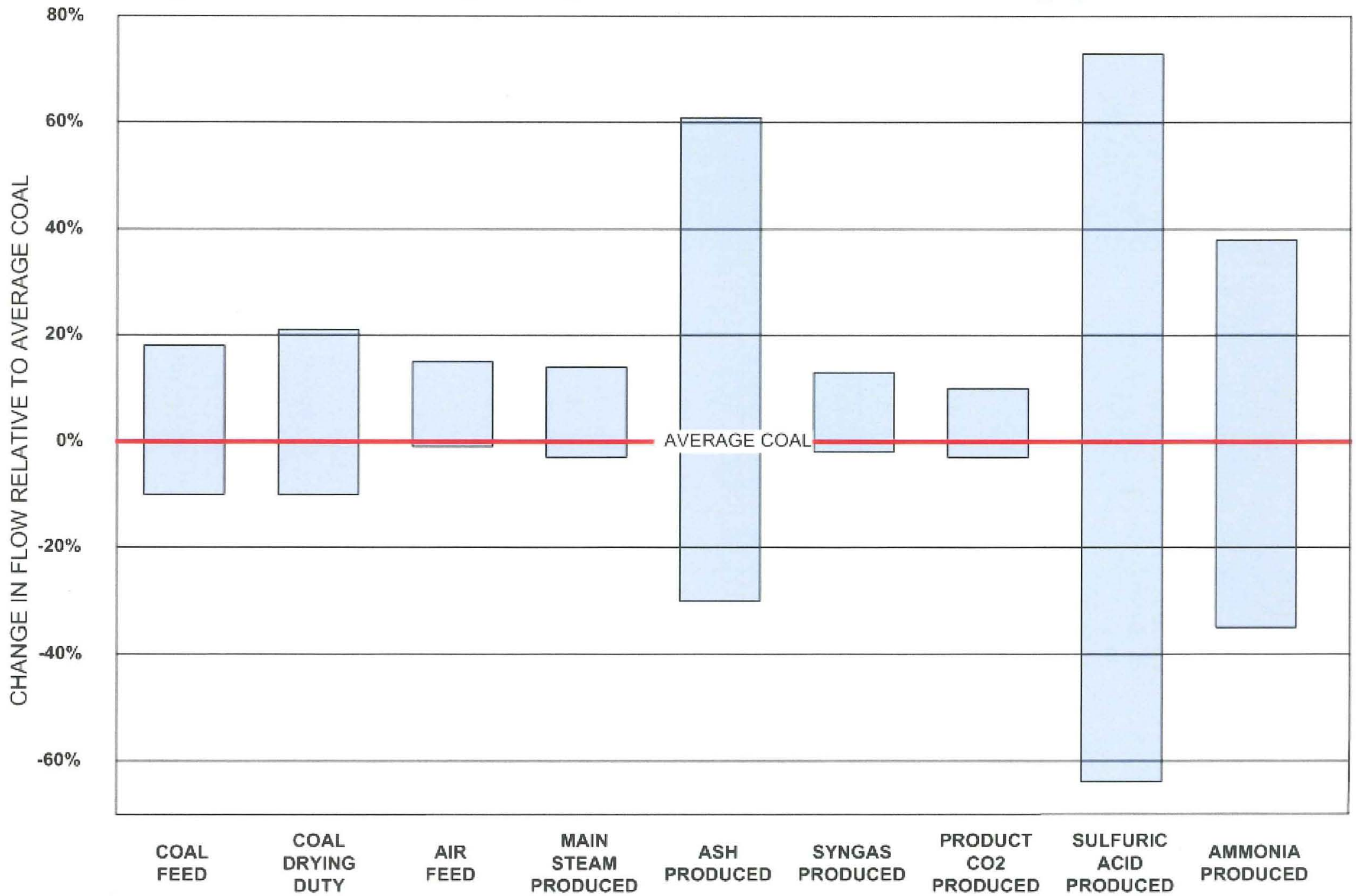
Effect of Coal Variability on Kemper County Operations and Byproducts

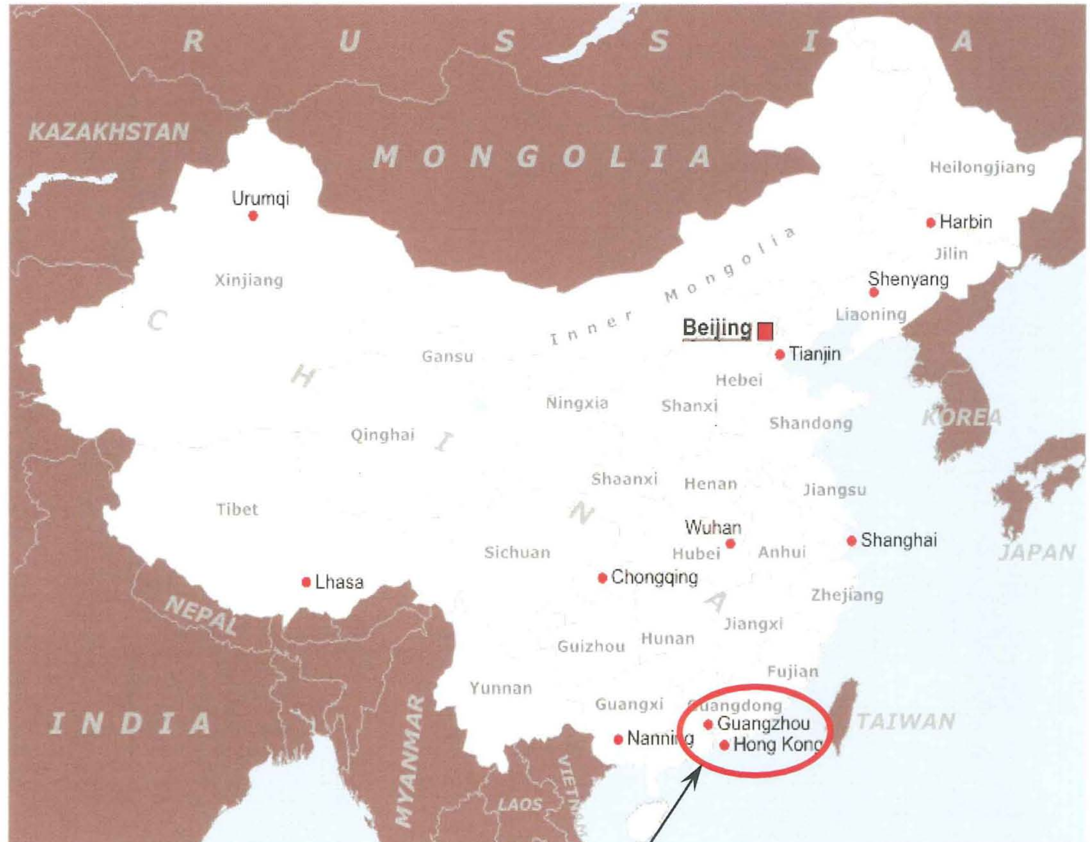


TRIG™ TRANSPORT INTEGRATED GASIFICATION

SOUTHERN COMPANY *Energy to Serve Your World*

Dongguan, China TRIG™ Project

- <u>Location:</u> TianMing Electric Power (TMEP), Dongguan, China
- <u>Project Scope:</u>
  - Re-fueling of existing gas turbines in 2x1 oil-fueled 120 MW combined cycle plant.
- <u>Southern's Role</u>
  - KBR has prime contract to supply engineering design for TRIG™ gasifier island.
  - Southern is sub-contractor to KBR.
  - Chinese engineering teams supplying balance of EPC function with Southern's support.
  - Southern is supplying consulting services to TMEP to support implementation and operations.



Dongguan is located between Hong Kong and Guangzhou in Pearl River Delta region of Southern China.

TRIG™ TRANSPORT INTEGRATED GASIFICATION

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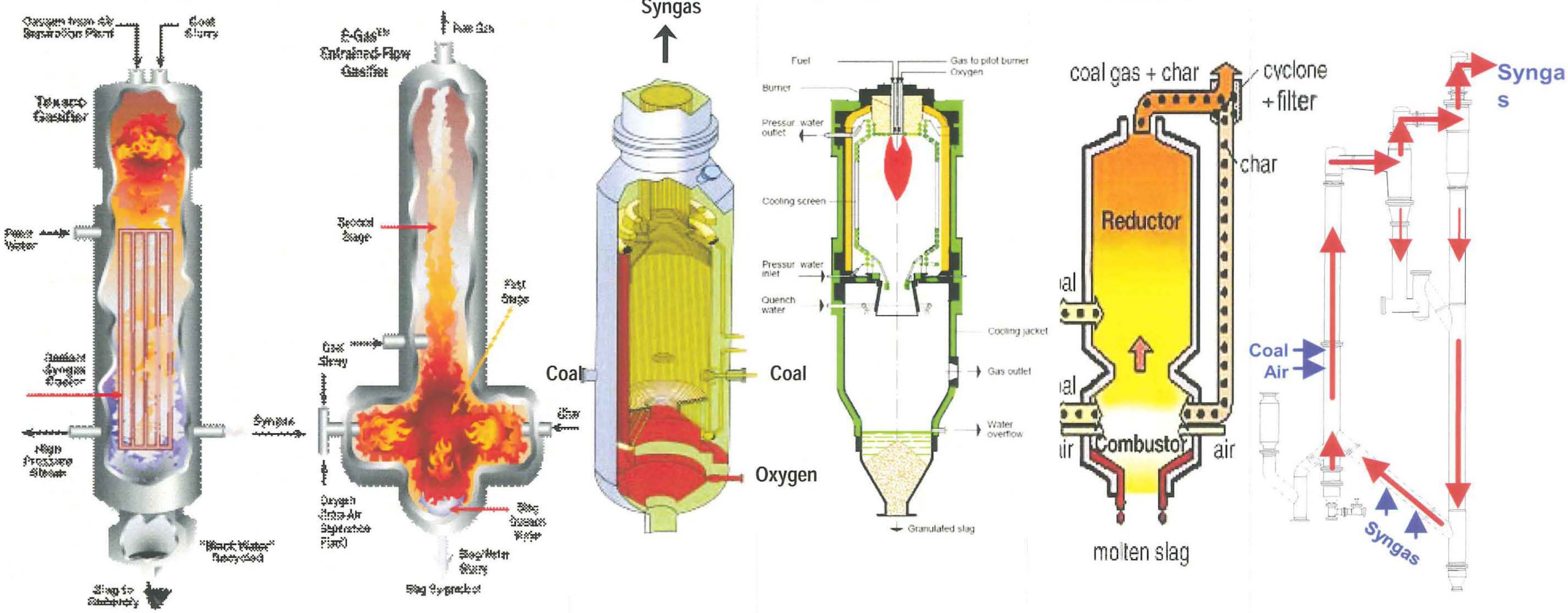
Visual Comparison of Main Gasifier Types

(Not to Scale)

GE | **Conoco** | **Shell** | **Siemens** | **MHI** | **TRIG™**



Entrained Flow (Once Through)	Fluid Bed
Oxygen-blown	Air-or O_2 -blown
Burner-type, slagging	No-burner Non-slagging

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Development of TRIG™ for Power and Chemical Production

TRIG™ Leverages Long History of KBR Fluid Catalytic Cracking (FCC) Expertise

- Late 30's — First Commercial FCC Unit for Exxon
- 1942 — Orthoflow™ A Design
- 1951 — Orthoflow™ C Design
- Early 1960's — Resid FCCs
- 1976 — Orthoflow™ F Design

1980's

Design Based on FCC Technology

1990

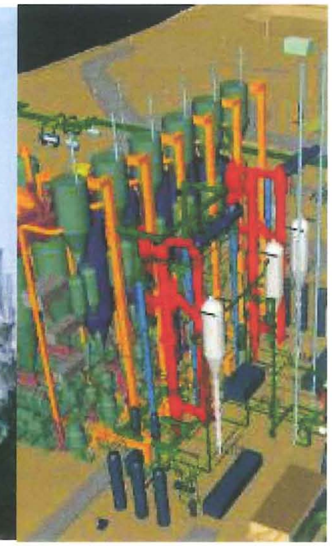
Pilot Plant Tech Center

1996

Grand Forks, ND 2,600 Hours Test Run

1996

PSDF-Wilsonville, AL. >15,600 hrs in gasification >2,200 hrs on Mississippi Lignite thru July '11



China 2011 USA 2014

TRIG™ In Kemper County, MS, USA & Dong Guan, China

TRIG™ TRANSPORT INTEGRATED GASIFICATION

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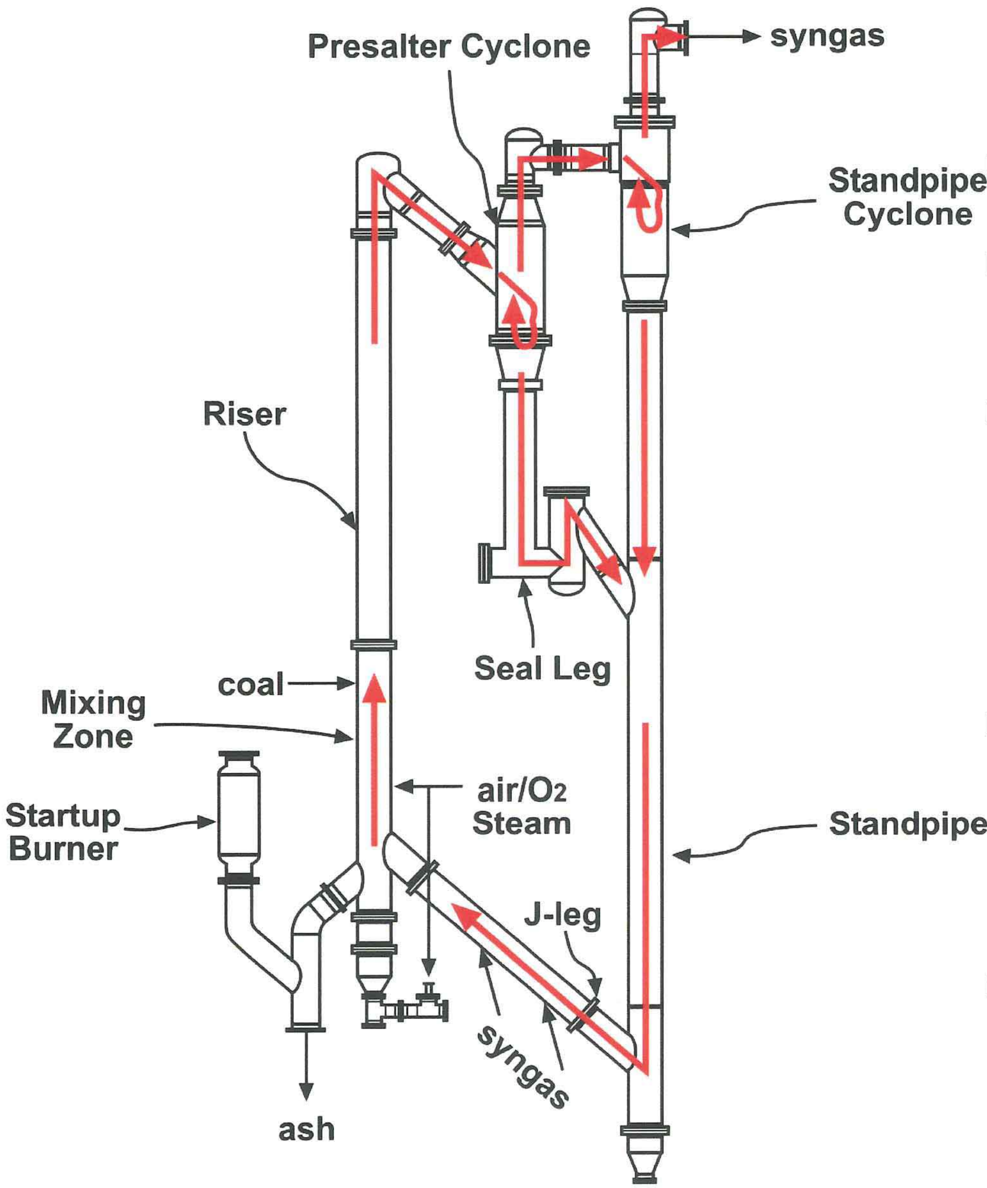

TRIG™ Attributes/Advantages

- **Simple, well established design**
  - Based on technology in use for 70 years
- **Either Air- or Oxygen-blown**
  - Air for power
  - Oxygen for liquid fuels and chemicals
- **High Reliability Design**
  - Non-slagging design:
    - Provides 10-20 year refractory life,
    - Eliminates black water system
    - Provides non-fouling syngas cooler operation
  - No burners to fail and be replaced
  - Dry dust removal eliminates gray water system
- **Lower Fuel Costs**
  - Coarse, dry coal feed allows:
    - Fewer, lower power pulverizers, and
    - Less drying than other dry-feed gasifiers
  - Cost-effective using high moisture, high-ash, low rank coals (PRB and lignite).
- **Excellent Environmental Performance**
  - Lower water use compared to pulverized coal (PC)
  - Excellent emissions performance
  - Easier to permit compared to PC
  - Lower cost carbon capture compared to PC

TRIG™ TRANSPORT INTEGRATED GASIFICATION

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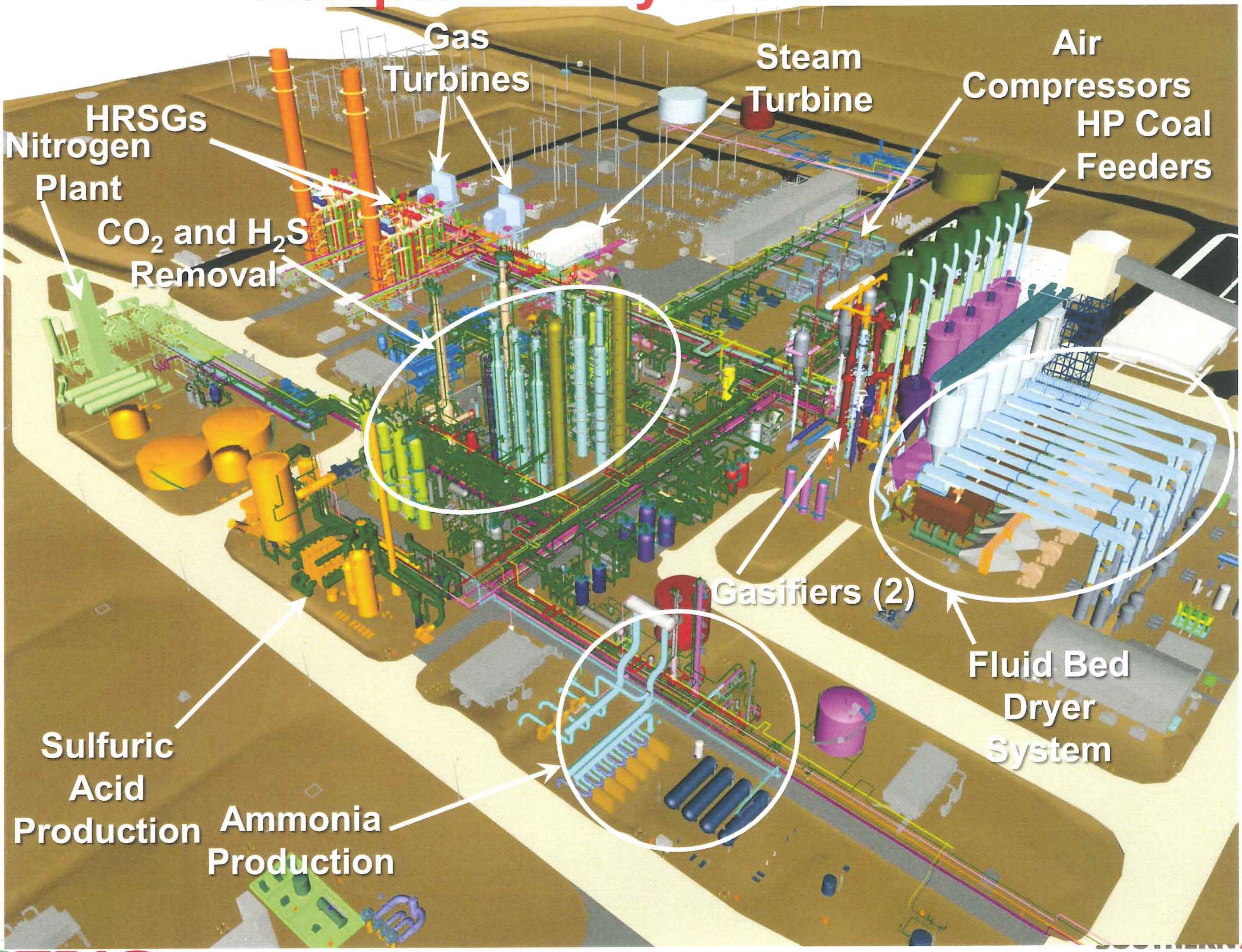
Kemper County IGCC 3-D



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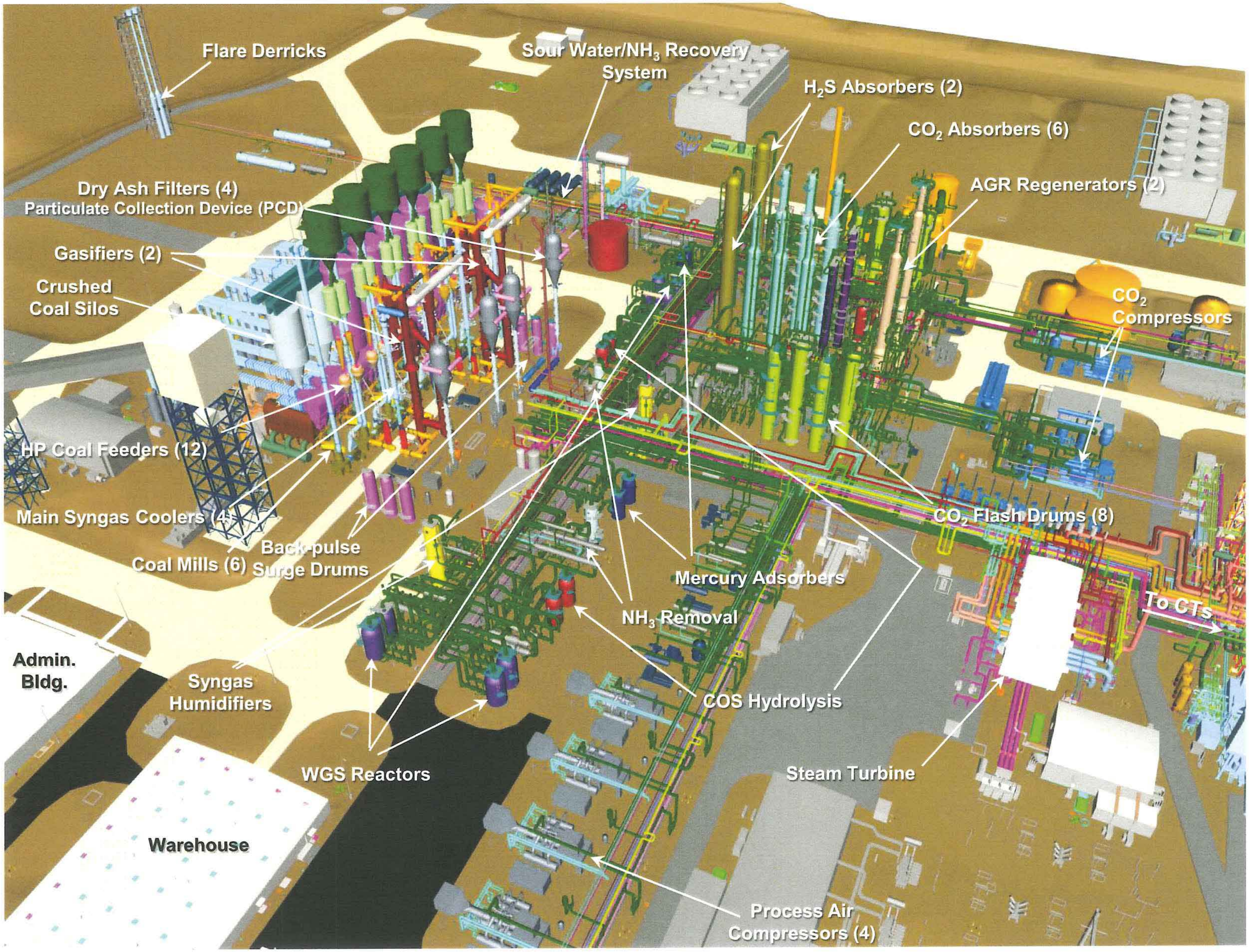
Kemper County IGCC 3-D



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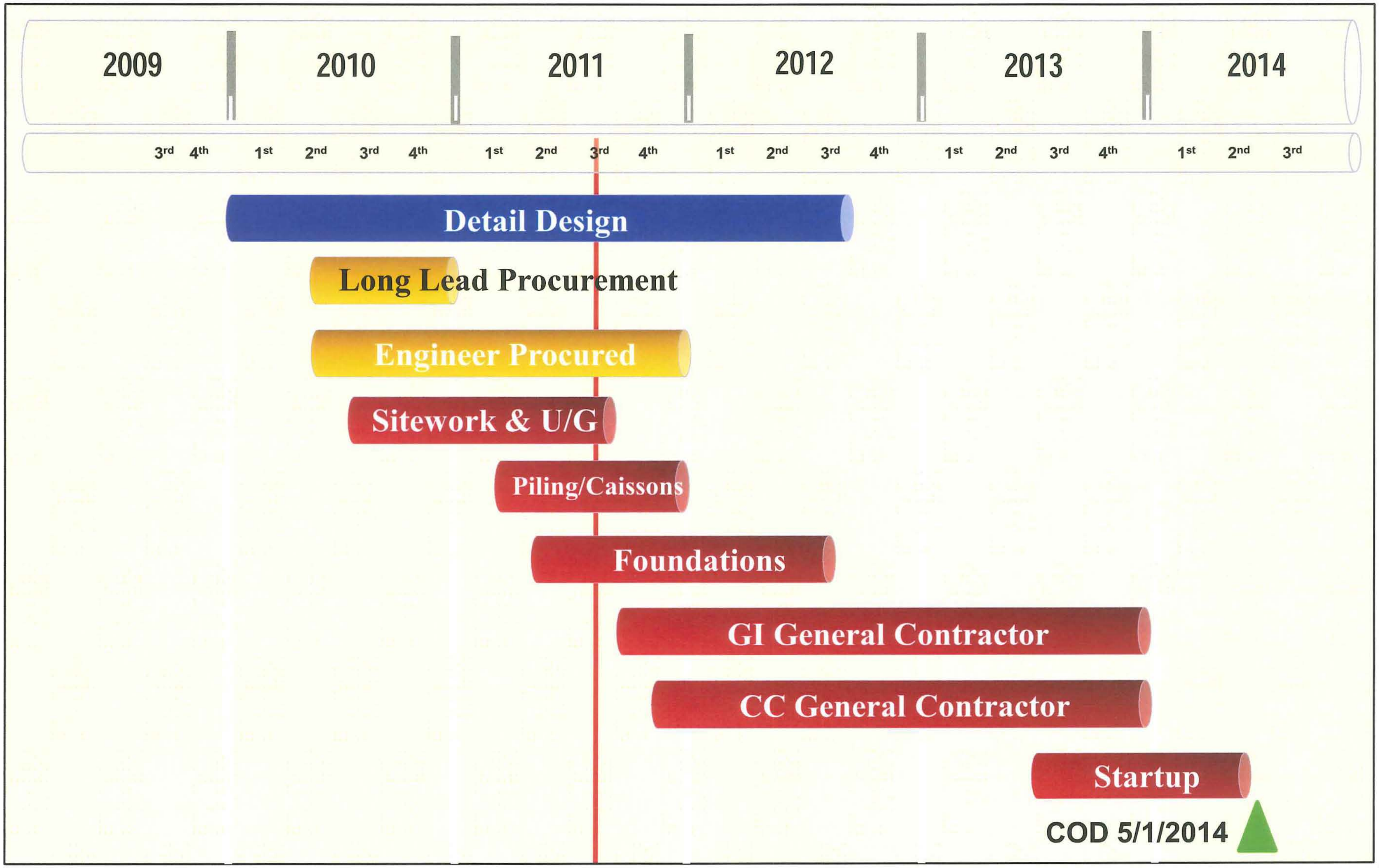
Kemper County IGCC Timeline & Milestones



TRIG
TRANSPORT INTEGRATED GASIFICATION

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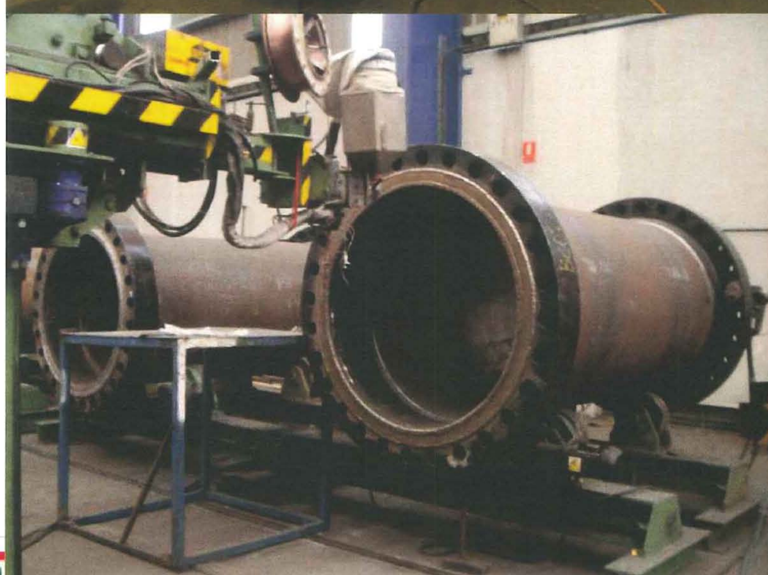
Kemper Procurement Update
PCD Fines Receiver
October- 2011



TRANSPORT INTEGRATED GASIFICATION

HERN COMPANY

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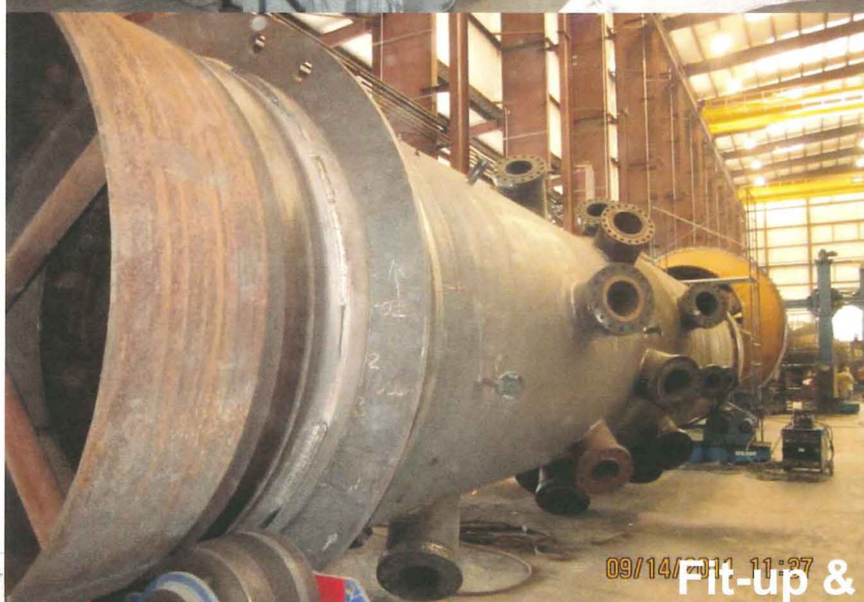
Kemper Procurement Update – Gasifier October- 2011



Fit-up & Welding

Kemper Procurement Update
CO_2 Control Equipment
October- 2011

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SOUTHERN COMPANY
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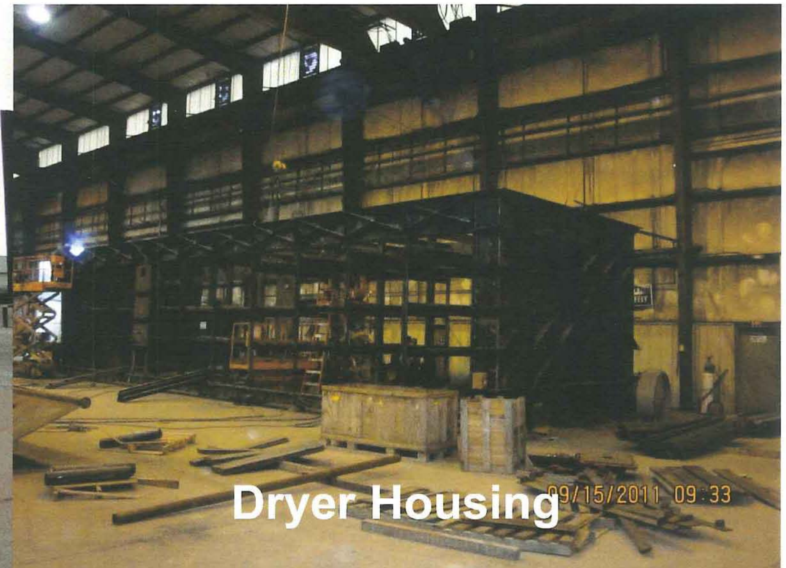
Kemper Procurement Update
Fluid Bed Dryer Housing
October- 2011



Kemper Construction Update
October- 2011


TRANSPORT INTEGRATED GASIFICATION

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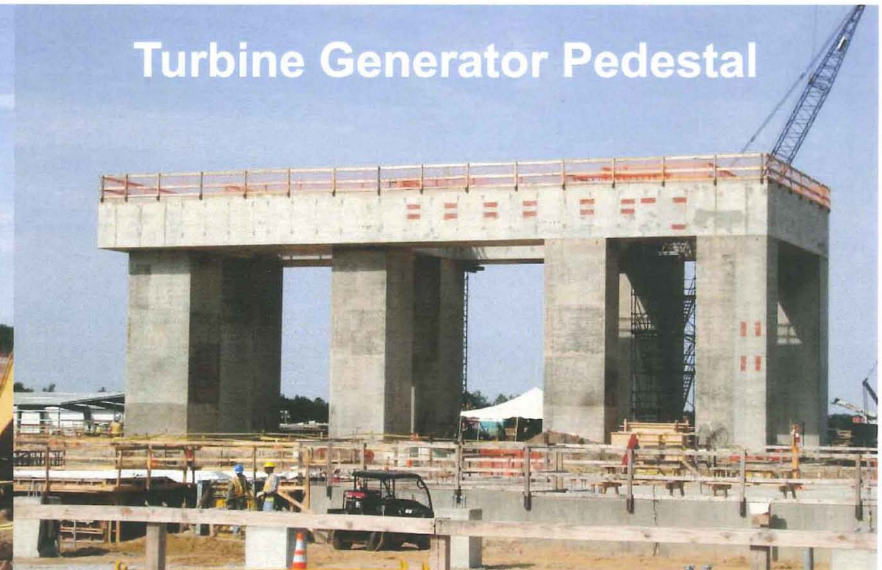
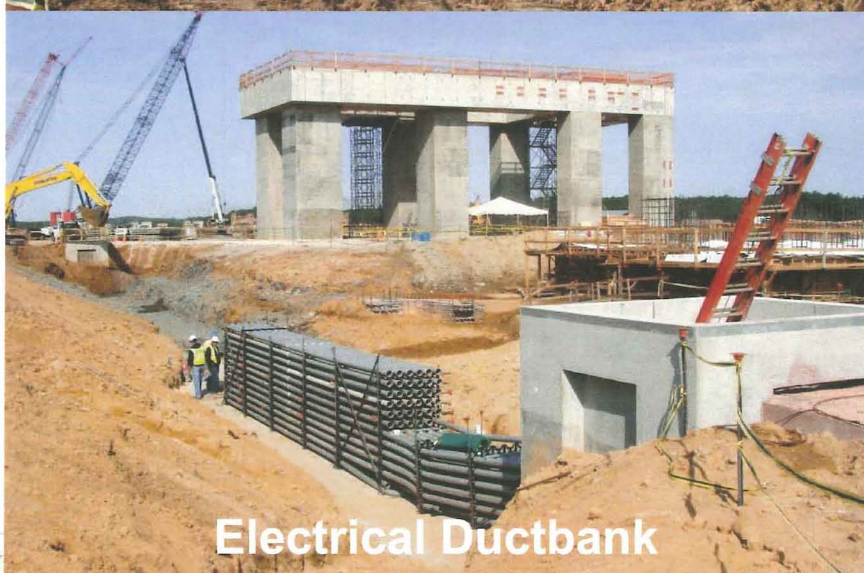
Kemper Construction Update
October- 2011





Kemper Construction Update
October- 2011

Kemper Construction Update
October- 2011

TRANSPORT INTEGRATED GASIFICATION

ANY

Energy to Serve Your World®

CO_2 Stationary Source and Geologic Storage Resource Estimates by State/Province

APPENDIX C

Prepared for

U.S. Department of Energy
National Energy Technology Laboratory
Carbon Sequestration Program

Prepared by

DOE Regional Carbon Sequestration Partnerships and
the National Carbon Sequestration Database and Geographic Information System

September 2010

CO_2 Stationary Source Emission Estimates by State/Province

The table ("Identified Stationary CO_2 Sources") displays CO_2 stationary source data by state/province which were obtained from the RCSPs and compiled by NATCARB. As described on page 25, a total of more than 4,507 stationary sources with total annual emissions exceeding 3,400 million metric tons (3,748 million tons) of CO_2 have been documented by the RCSPs.

Information on the methods used in estimating CO_2 stationary source emissions can be found in the "CO_2 Stationary Source Emission Estimation Methodologies Summary" in Appendix A. Emissions data specific to each RCSP can be found within each RCSP section of *Atlas III*.

The States/provinces with the largest CO_2 stationary source emissions include Texas, Alberta, Indiana, Ohio, Florida, Pennsylvania, Illinois, Louisiana, West Virginia, and Missouri. The 343 stationary sources identified in Texas are estimated to emit 373 million metric tons per year (411 million tons per year) of CO_2. The 305 stationary sources identified in Alberta are estimated to emit 208 million metric tons per year (229 million tons per year). The 92 stationary sources identified in Indiana are estimated to emit 155 million metric tons per year (171 million tons per year).

Identified Stationary CO_2 Sources

State/Province	CO_2 Emissions Million Metric Ton Per Year	Number of Sources
Alabama	80	59
Alaska	20	49
Alberta	208	305
Arizona	55	50
Arkansas	35	30
British Columbia	15	53
California	84	182
Colorado	52	56
Connecticut	10	63
Delaware	6	16
District of Columbia	0	5
Florida	143	108
Georgia	90	64
Hawaii	10	45
Idaho	2	18
Illinois	122	138
Indiana	155	92
Iowa	55	63
Kansas	48	102
Kentucky	93	48
Louisiana	102	133
Maine	5	106
Manitoba	4	12
Maryland	37	21
Massachusetts	25	137
Michigan	84	45
Minnesota	59	103
Mississippi	34	49
Missouri	98	126
Montana	28	78
Nebraska	31	35
Nevada	27	16

State/Province	CO_2 Emissions Million Metric Ton Per Year	Number of Sources
New Brunswick	6	7
New Hampshire	8	66
New Jersey	35	123
New Mexico	35	32
New York	77	386
Newfoundland & Labrador	4	7
North Carolina	77	55
North Dakota	42	31
Northwest Territories	0	2
Nova Scotia	11	7
Ohio	149	51
Oklahoma	57	45
Ontario	50	48
Oregon	11	22
Pennsylvania	142	76
Quebec	14	32
Rhode Island	2	18
Saskatchewan	42	35
South Carolina	40	48
South Dakota	21	53
Tennessee	66	29
Texas	373	343
Utah	43	27
Vermont	0	73
Virginia	46	56
Washington	21	35
West Virginia	99	26
Wisconsin	77	219
Wyoming	59	101
Offshore	46	47
TOTAL	3,467	4,507

Total CO_2 Storage Resource Estimates by State/Province

The table ("Total CO_2 Storage Resource") displays the total CO_2 storage resource estimates by state/province which were obtained from the RCSPs and compiled by NATCARB. The total CO_2 storage resource is the sum of saline formation, oil and gas reservoir, and unmineable coal area CO_2 storage resource estimates. The current total CO_2 storage resource identified by the RCSPs is approximately 1,850 to 20,470 billion metric tons (2,040 to 22,570 billion tons).

Information on the methods used in estimating CO_2 storage resource can be found in the "Methodology for Development of Geologic Storage Estimates for Carbon Dioxide" in Appendix B. Please note CO_2 geologic storage information in *Atlas III* was developed to provide a high level overview of CO_2 geologic storage potential across the United States and parts of Canada. Carbon dioxide resource estimates presented are intended to be used as an initial assessment of potential geologic storage. This information provides CCS project developers a starting point for further investigation of the extent to which geologic CO_2 storage is feasible. This information is not intended as a substitute for site-specific characterization, assessment and testing. Please refer to page 14 of *Atlas III* for additional information on this level of assessment.

*Total CO_2 Storage Resource**

State/Province	Million Metric Tons		Million Tons	
	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	14,020	166,320	15,454	183,336
Alaska	8,980	20,530	9,899	22,630
Alberta	46,080	50,170	50,795	55,303
Arizona	130	1,590	143	1,753
Arkansas	6,150	63,260	6,779	69,732
British Columbia	1,600	2,130	1,764	2,348
California	33,510	416,930	36,938	459,587
Colorado	32,960	426,800	36,332	470,466
Connecticut	0	0	0	0
Delaware	20	80	22	88
District of Columbia	0	0	0	0
Florida	17,120	219,850	18,872	242,343
Georgia	520	23,260	573	25,640
Hawaii				
Idaho	50	720	55	794
Illinois	10,040	118,290	11,067	130,392
Indiana	14,480	85,650	15,961	94,413
Iowa	10	160	11	176
Kansas	2,780	18,000	3,064	19,842
Kentucky	1,530	9,750	1,687	10,748
Louisiana	168,270	2,083,280	185,486	2,296,423
Maine				
Manitoba	1,050	1,050	1,157	1,157
Maryland	860	5,050	948	5,567
Massachusetts	0	0	0	0
Michigan	15,390	59,260	16,965	65,323
Minnesota				
Mississippi	51,460	637,970	56,725	703,242
Missouri	20	320	22	353
Montana	123,630	1,656,640	136,279	1,826,133
Nebraska	22,890	76,870	25,232	84,735
Nevada	0	0	0	0
New Brunswick				
New Hampshire				
New Jersey	0	0	0	0
New Mexico	39,550	449,300	43,596	495,268
New York	2,620	7,740	2,888	8,532
Newfoundland & Labrador				
North Carolina	1,320	18,170	1,455	20,029
North Dakota	108,230	125,080	119,303	137,877
Northwest Territories				
Nova Scotia				
Ohio	14,140	26,110	15,587	28,781
Oklahoma	8,120	8,130	8,951	8,962
Ontario	10	20	11	22
Oregon	7,080	97,390	7,804	107,354
Pennsylvania	10,100	30,920	11,133	34,083
Quebec	0	0	0	0
Rhode Island	0	0	0	0
Saskatchewan	7,900	15,740	8,708	17,350
South Carolina	200	9,660	220	10,648
South Dakota	17,580	156,180	19,379	172,159
Tennessee	490	6,650	540	7,330
Texas	393,490	4,662,190	433,748	5,139,185
Utah	22,180	289,960	24,449	319,626
Vermont	0	0	0	0
Virginia	330	1,240	364	1,367
Washington	29,930	411,570	32,992	453,678
West Virginia	6,630	20,260	7,308	22,333
Wisconsin	0	0	0	0
Wyoming	101,590	1,216,640	111,984	1,341,116
Offshore	509,220	6,776,230	561,319	7,469,515
TOTAL	1,854,260	20,473,110	2,043,972	22,567,741

* States/Provinces with a "zero" value represent estimates of minimal CO_2 storage resource, while states/provinces with a blank represent areas that have not yet been assessed by the RCSPs.

CO_2 Storage Resource Estimates for Oil and Gas Reservoirs by State/Province

The table ("CO_2 Storage Resource Estimates for Oil and Gas Reservoirs") displays oil and gas reservoir CO_2 storage resource estimates by state/province. As described on page 28, the RCSPs have documented the location of more than 142 billion metric tons (156 billion tons) of CO_2 storage potential in oil and gas reservoirs distributed over 29 States and 4 provinces. In the table, States/provinces with a "zero" value represent estimates of minimal oil and gas reservoir CO_2 storage resource while States/provinces with a blank represent areas that have not yet been assessed by the RCSPs. Carbon dioxide storage resource data for oil and gas reservoirs specific to each RCSP can be found within each RCSP section of *Atlas III*. Additional details can be obtained from the NATCARB website (http://www.natcarb.org/).

Areas with the largest oil and gas reservoir storage potential identified include Texas, offshore, Louisiana, Alberta, Ohio, Oklahoma, New Mexico, Saskatchewan, North Dakota, and California. These CO_2 storage resources are significant, with an estimated 120 years of storage available in Texas oil and gas reservoirs at Texas's current emission rate. Oklahoma's oil and gas reservoirs are estimated to have CO_2 storage resource for more than 140 years of emissions from the state.

Please note CO_2 geologic storage information in *Atlas III* was developed to provide a high level overview of CO_2 geologic storage potential across the United States and parts of Canada. Carbon dioxide resource estimates presented are intended to be used as an initial assessment of potential geologic storage. This information provides CCS project developers a starting point for further investigation of the extent to which geologic CO_2 storage is feasible. This information is not intended as a substitute for site-specific characterization, assessment and testing. Please refer to page 14 of *Atlas III* for additional information on this level of assessment.

*CO_2 Storage Resource Estimates for Oil & Gas Reservoirs by State/Province**

State/Province	Million Metric Tons	Million Tons
Alabama	350	386
Alaska		
Alberta	10,090	11,122
Arizona	10	11
Arkansas	260	287
British Columbia	10	11
California	3,440	3,792
Colorado	1,610	1,775
Connecticut		
Delaware		
District of Columbia		
Florida	130	143
Georgia		
Hawaii		
Idaho		
Illinois	100	110
Indiana	20	22
Iowa		
Kansas	1,590	1,753
Kentucky	50	55
Louisiana	10,610	11,696
Maine		
Manitoba	740	816
Maryland		
Massachusetts		
Michigan	770	849
Minnesota		
Mississippi	560	617
Missouri	0	0
Montana	2,600	2,866
Nebraska	30	33
Nevada		

* States/Provinces with a "zero" value represent estimates of minimal CO_2 storage resource, while states/provinces with a blank represent areas that have not yet been assessed by the RCSPs.

State/Province	Million Metric Tons	Million Tons
New Brunswick		
New Hampshire		
New Jersey		
New Mexico	7,350	8,102
New York	920	1,014
Newfoundland & Labrador		
North Carolina		
North Dakota	4,410	4,861
Northwest Territories		
Nova Scotia		
Ohio	10,060	11,089
Oklahoma	8,120	8,951
Ontario		
Oregon		
Pennsylvania	2,970	3,274
Quebec		
Rhode Island		
Saskatchewan	6,920	7,628
South Carolina		
South Dakota	190	209
Tennessee	0	0
Texas	46,200	50,927
Utah	1,160	1,279
Vermont		
Virginia	60	66
Washington		
West Virginia	1,830	2,017
Wisconsin		
Wyoming	2,300	2,535
Offshore	16,790	18,508
TOTAL	142,250	156,804

CO_2 Storage Resource Estimates for Unmineable Coal Areas by State/Province

The table ("CO_2 Storage Resource Estimates for Unmineable Coal Areas") displays unmineable coal area CO_2 storage resource estimates by state/province. As described on page 29, the RCSPs have documented the location of more than 59 to 117 billion metric tons (65 to 128 billion tons) of CO_2 geologic storage potential in unmineable coal areas distributed over 29 States and 1 province. In the table, States/provinces with a zero represent estimates of minimal unmineable coal area CO_2 storage resource while States/provinces with a blank represent areas that have not yet been assessed by the RCSPs. Unmineable coal area CO_2 storage resource data specific to each RCSP can be found within each RCSP section of *Atlas III*. Additional details can be obtained from the NATCARB website (http://www.natcarb.org/).

Areas with the largest unmineable coal area CO_2 storage resource identified include Texas, Alaska, Louisiana, Mississippi, Wyoming, Alabama, Arkansas, offshore, Illinois, and Florida. An estimated 35 to 85 years of CO_2 storage resource is available in Texas unmineable coal areas for Texas's current emission rate. Alaska's unmineable coal areas alone are estimated to have CO_2 storage resource for 24 to 55 years worth of emissions from the state.

Please note CO_2 geologic storage information in *Atlas III* was developed to provide a high level overview of CO_2 geologic storage potential across the United States and parts of Canada. Carbon dioxide resource estimates presented are intended to be used as an initial assessment of potential geologic storage. This information provides CCS project developers a starting point for further investigation of the extent to which geologic CO_2 storage is feasible. This information is not intended as a substitute for site-specific characterization, assessment and testing. Please refer to page 14 of *Atlas III* for additional information on this level of assessment.

*CO_2 Storage Resource Estimates for Unmineable Coal Areas by State/Province**

State/Province	Million Metric Tons		Million Tons	
	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	1,910	4,340	2,105	4,784
Alaska	8,980	20,530	9,899	22,630
Alberta	840	840	926	926
Arizona	0	0	0	0
Arkansas	1,570	3,580	1,731	3,946
British Columbia				
California				
Colorado	490	860	540	948
Connecticut				
Delaware				
District of Columbia				
Florida	1,240	2,810	1,367	3,097
Georgia	30	60	33	66
Hawaii				
Idaho				
Illinois	1,450	2,860	1,598	3,153
Indiana	90	190	99	209
Iowa	0	10	0	11
Kansas	0	10	0	11
Kentucky	130	250	143	276
Louisiana	8,300	18,910	9,149	20,845
Maine				
Manitoba				
Maryland				
Massachusetts				
Michigan				
Minnesota				
Mississippi	5,450	12,470	6,008	13,746
Missouri	0	10	0	11
Montana	320	320	353	353
Nebraska	0	0	0	0
Nevada				
New Brunswick				
New Hampshire				
New Jersey				
New Mexico	80	300	88	331
New York				
Newfoundland & Labrador				
North Carolina				
North Dakota	600	600	661	661
Northwest Territories				
Nova Scotia				
Ohio	110	150	121	165
Oklahoma	0	10	0	11
Ontario				
Oregon				
Pennsylvania	230	330	254	364
Quebec				
Rhode Island				
Saskatchewan				
South Carolina				
South Dakota				
Tennessee	0	0	0	0
Texas	13,890	31,740	15,311	34,987
Utah	30	120	33	132
Vermont				
Virginia	190	790	209	871
Washington	0	0	0	0
West Virginia	320	500	353	551
Wisconsin				
Wyoming	11,860	12,140	13,073	13,382
Offshore	1,350	3,080	1,488	3,395
TOTAL	59,460	117,810	65,543	129,863

* States/Provinces with a "zero" value represent estimates of minimal CO_2 storage resource, while states/provinces with a blank represent areas that have not yet been assessed by the RCSPs.

Saline Formation Storage Resource Estimates by State/Province

The table ("CO_2 Storage Resource Estimates for Saline Formations by State/Province") displays saline formation CO_2 storage resource estimates by state/province. As described on page 27, the RCSPs have documented the location of saline formations with an estimated storage potential from approximately 1,650 to more than 20,200 billion metric tons (from 1,820 to more than 22,260 billion tons). In the table, States/provinces with a zero represent estimates of saline formation CO_2 storage resource while States/provinces with a blank represent areas that have not yet been assessed by the RCSPs. Saline formation CO_2 storage resource data specific to each RCSP can be found within each RCSP section of *Atlas III*. Additional details can be obtained from the NATCARB website (http://www.natcarb.org/).

Areas with the largest saline formation CO_2 storage resource identified include offshore, Texas, Louisiana, Montana, Wyoming, Mississippi, New Mexico, Colorado, California, and Washington. At Texas's current emission rate, there is an estimated 890 to 12,290 years of CO_2 storage resource available in Texas saline formations.

Please note CO_2 geologic storage information in *Atlas III* was developed to provide a high level overview of CO_2 geologic storage potential across the United States and parts of Canada. Carbon dioxide resource estimates presented are intended to be used as an initial assessment of potential geologic storage. This information provides CCS project developers a starting point for further investigation of the extent to which geologic CO_2 storage is feasible. This information is not intended as a substitute for site-specific characterization, assessment and testing. Please refer to page 14 of *Atlas III* for additional information on this level of assessment.

*CO_2 Storage Resource Estimates for Saline Formations by State/Province**

State/Province	Million Metric Tons		Million Tons	
	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	11,760	161,630	12,963	178,167
Alaska				
Alberta	35,150	39,240	38,746	43,255
Arizona	120	1,580	132	1,742
Arkansas	4,320	59,420	4,762	65,499
British Columbia	1,590	2,120	1,753	2,337
California	30,070	413,490	33,147	455,795
Colorado	30,860	424,330	34,017	467,744
Connecticut	0	0	0	0
Delaware	20	80	22	88
District of Columbia	0	0	0	0
Florida	15,750	216,910	17,361	239,102
Georgia	490	23,200	540	25,574
Hawaii				
Idaho	50	720	55	794
Illinois	8,490	115,330	9,359	127,130
Indiana	14,370	85,440	15,840	94,181
Iowa	10	150	11	165
Kansas	1,190	16,400	1,312	18,078
Kentucky	1,350	9,450	1,488	10,417
Louisiana	149,360	2,053,760	164,641	2,263,883
Maine				
Manitoba	310	310	342	342
Maryland	860	5,050	948	5,567
Massachusetts	0	0	0	0
Michigan	14,620	58,490	16,116	64,474
Minnesota				
Mississippi	45,450	624,940	50,100	688,878
Missouri	20	310	22	342
Montana	120,710	1,653,720	133,060	1,822,914
Nebraska	22,860	76,840	25,199	84,702
Nevada	0	0	0	0
New Brunswick				
New Hampshire				
New Jersey	0	0	0	0
New Mexico	32,120	441,650	35,406	486,836
New York	1,700	6,820	1,874	7,518
Newfoundland & Labrador				
North Carolina	1,320	18,170	1,455	20,029
North Dakota	103,220	120,070	113,781	132,355
Northwest Territories				
Nova Scotia				
Ohio	3,970	15,900	4,376	17,527
Oklahoma	0	0	0	0
Ontario	10	20	11	22
Oregon	7,080	97,390	7,804	107,354
Pennsylvania	6,900	27,620	7,606	30,446
Quebec	0	0	0	0
Rhode Island	0	0	0	0
Saskatchewan	980	8,820	1,080	9,722
South Carolina	200	9,660	220	10,648
South Dakota	17,390	155,990	19,169	171,950
Tennessee	490	6,650	540	7,330
Texas	333,400	4,584,250	367,511	5,053,271
Utah	20,990	288,680	23,138	318,215
Vermont	0	0	0	0
Virginia	80	390	88	430
Washington	29,930	411,570	32,992	453,678
West Virginia	4,480	17,930	4,938	19,764
Wisconsin	0	0	0	0
Wyoming	87,430	1,202,200	96,375	1,325,199
Offshore	491,080	6,756,360	541,323	7,447,612
TOTAL	1,652,550	20,213,050	1,821,625	22,281,074

* States/Provinces with a "zero" value represent estimates of minimal CO_2 storage resource, while states/provinces with a blank represent areas that have not yet been assessed by the RCSPs.

CO_2 Stationary Source Emissions and CO_2 Storage Resource Estimates Summary by State/Province

This table ("CO_2 Emissions and Geologic Storage Resource Summary") is a compilation of all data provided in this Appendix. State/Provinces with the "zero" represents estimates of the minimal CO_2 storage resource while States/Provinces with a blank represent areas that have not yet been accessed by the RCSPs.

Please note CO_2 geologic storage information in *Atlas III* was developed to provide a high level overview of CO_2 geologic storage potential across the United States and parts of Canada. Carbon dioxide resource estimates presented are intended to be used as an initial assessment of potential geologic storage. This information provides CCS project developers a starting point for further investigation of the extent to which geologic CO_2 storage is feasible. This information is not intended as a substitute for site-specific characterization, assessment and testing. Please refer to page 14 of *Atlas III* for additional information on this level of assessment.

CO_2 Emissions			Oil and Gas Reservoir Storage Resource	Unmineable Coal Areas Storage Resource		Saline Formation Storage Resource		Total Storage Resource	
			Million Metric Tons	Million Metric Tons		Million Metric Tons		Million Metric Tons	
State/Province	Million Metric Ton/Year	No. Sources		Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	80	59	350	1,910	4,340	11,760	161,630	14,020	166,320
Alaska	20	49		8,980	20,530			8,980	20,530
Alberta	208	305	10,090	840	840	35,150	39,240	46,080	50,170
Arizona	55	50	10	0	0	120	1,580	130	1,590
Arkansas	35	30	260	1,570	3,580	4,320	59,420	6,150	63,260
British Columbia	15	53	10			1,590	2,120	1,600	2,130
California	84	182	3,440			30,070	413,490	33,510	416,930
Colorado	52	56	1,610	490	860	30,860	424,330	32,960	426,800
Connecticut	10	63				0	0	0	0
Delaware	6	16				20	80	20	80
District of Columbia	0	5				0	0	0	0
Florida	143	108	130	1,240	2,810	15,750	216,910	17,120	219,850
Georgia	90	64		30	60	490	23,200	520	23,260
Hawaii	10	45							
Idaho	2	18				50	720	50	720
Illinois	122	138	100	1,450	2,860	8,490	115,330	10,040	118,290
Indiana	155	92	20	90	190	14,370	85,440	14,480	85,650
Iowa	55	63		0	10	10	150	10	160
Kansas	48	102	1,590	0	10	1,190	16,400	2,780	18,000
Kentucky	93	48	50	130	250	1,350	9,450	1,530	9,750
Louisiana	102	133	10,610	8,300	18,910	149,360	2,053,760	168,270	2,083,280
Maine	5	106							
Manitoba	4	12	740			310	310	1,050	1,050
Maryland	37	21				860	5,050	860	5,050
Massachusetts	25	137				0	0	0	0
Michigan	84	45	770			14,620	58,490	15,390	59,260
Minnesota	59	103							
Mississippi	34	49	560	5,450	12,470	45,450	624,940	51,460	637,970
Missouri	98	126	0	0	10	20	310	20	320
Montana	28	78	2,600	320	320	120,710	1,653,720	123,630	1,656,640
Nebraska	31	35	30	0	0	22,860	76,840	22,890	76,870

CO_2 Emissions			Oil and Gas Reservoir Storage Resource	Unmineable Coal Areas Storage Resource		Saline Formation Storage Resource		Total Storage Resource	
			Million Metric Tons	Million Metric Tons		Million Metric Tons		Million Metric Tons	
State/Province	Million Metric Ton/Year	No. Sources		Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Nevada	27	16				0	0	0	0
New Brunswick	6	7							
New Hampshire	8	66							
New Jersey	35	123				0	0	0	0
New Mexico	35	32	7,350	80	300	32,120	441,650	39,550	449,300
New York	77	386	920			1,700	6,820	2,620	7,740
Newfoundland & Labrador	4	7							
North Carolina	77	55				1,320	18,170	1,320	18,170
North Dakota	42	31	4,410	600	600	103,220	120,070	108,230	125,080
Northwest Territories	0	2							
Nova Scotia	11	7							
Ohio	149	51	10,060	110	150	3,970	15,900	14,140	26,110
Oklahoma	57	45	8,120	0	10	0	0	8,120	8,130
Ontario	50	48				10	20	10	20
Oregon	11	22				7,080	97,390	7,080	97,390
Pennsylvania	142	76	2,970	230	330	6,900	27,620	10,100	30,920
Quebec	14	32				0	0	0	0
Rhode Island	2	18				0	0	0	0
Saskatchewan	42	35	6,920			980	8,820	7,900	15,740
South Carolina	40	48				200	9,660	200	9,660
South Dakota	21	53	190			17,390	155,990	17,580	156,180
Tennessee	66	29	0	0	0	490	6,650	490	6,650
Texas	373	343	46,200	13,890	31,740	333,400	4,584,250	393,490	4,662,190
Utah	43	27	1,160	30	120	20,990	288,680	22,180	289,960
Vermont	0	73				0	0	0	0
Virginia	46	56	60	190	790	80	390	330	1,240
Washington	21	35		0	0	29,930	411,570	29,930	411,570
West Virginia	99	26	1,830	320	500	4,480	17,930	6,630	20,260
Wisconsin	77	219				0	0	0	0
Wyoming	59	101	2,300	11,860	12,140	87,430	1,202,200	101,590	1,216,640
Offshore	46	47	16,790	1,350	3,080	491,080	6,756,360	509,220	6,776,230
TOTAL	3,467	4,507	142,250	59,460	117,810	1,652,550	20,213,050	1,854,260	20,473,110

* States/Provinces with a "zero" value represent estimates of minimal CO_2 storage resource, while states/provinces with a blank represent areas that have not yet been assessed by the RCSPs.

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Comparing Existing Pipeline Networks with the Potential Scale of Future U.S. CO_2 Pipeline Networks

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Abstract

Interest is growing regarding the potential size of a future U.S.-dedicated carbon dioxide (CO_2) pipeline infrastructure if carbon dioxide capture and storage (CCS) technologies are commercially deployed on a large scale within the United States. This paper assesses the potential scale of the CO_2 pipeline system needed under two hypothetical climate policies (WRE450 and WRE550 stabilization scenarios); a comparison is then made to the extant U.S. pipeline infrastructures used to deliver CO_2 for enhanced oil recovery and to move natural gas and liquid hydrocarbons from areas of production and importation to markets. The analysis reveals that between 11,000 and 23,000 additional miles of dedicated CO_2 pipeline might be needed in the United States before 2050 across these two cases. While either case represents a significant increase over the 3900 miles that comprise the existing national CO_2 pipeline infrastructure, it is important to realize that the demand for additional CO_2 pipeline capacity will unfold relatively slowly and in a geographically dispersed manner as new dedicated CCS-enabled power plants and industrial facilities are brought online. During the period 2010–2030, this analysis indicates growth in the CO_2 pipeline system on the order of a few hundred to less than 1000 miles per year. By comparison, during the period 1950–2000, the U.S. natural gas pipeline distribution system grew at rates that far exceed these growth projections for a future CO_2 pipeline network in the U.S. This analysis indicates that the need to increase the size of the existing dedicated CO_2 pipeline system should not be seen as a major obstacle for the commercial deployment of CCS technologies in the United States. While there could be issues associated with siting specific segments of a larger national CO_2 pipeline infrastructure, the sheer scale of the required infrastructure should not be seen as representing a significant impediment to U.S. deployment of CCS technologies.

Keywords: carbon dioxide capture and storage; pipelines, carbon management; climate change.

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1. Introduction

Interest and concern are growing regarding the potential size of the future U.S.-dedicated carbon dioxide (CO_2) pipeline infrastructure related to large-scale deployment of carbon dioxide capture and geologic storage (CCS) technologies. For example, in early 2008, the Congressional Research Service (CRS) stated, "[t]here is an increasing perception in Congress that a national CCS program could require the construction of a substantial network of interstate CO_2 pipelines." The CRS report lists a number of bills and one recently enacted public law that require assessments of the feasibility of creating a national CO_2 pipeline network as well as recommendations for the most cost-effective means of implementing a CO_2 transportation system [1]. In trying to understand the potential scale of a future national CO_2 pipeline network, comparisons are often made to the existing pipeline networks used to deliver natural gas and liquid hydrocarbons to markets within the United States. This paper assesses the potential scale of the CO_2 pipeline system needed under two hypothetical climate policies and compares these to the extant U.S. CO_2 pipeline infrastructure (See Figure 1, left-hand panel) and the interstate and intrastate natural gas transmission pipeline infrastructure (See Figure 1, right-hand panel). The analysis presented here suggests that the need to increase the size of the existing dedicated CO_2 pipeline system should not be seen as a significant obstacle for the commercial deployment of CCS technologies.

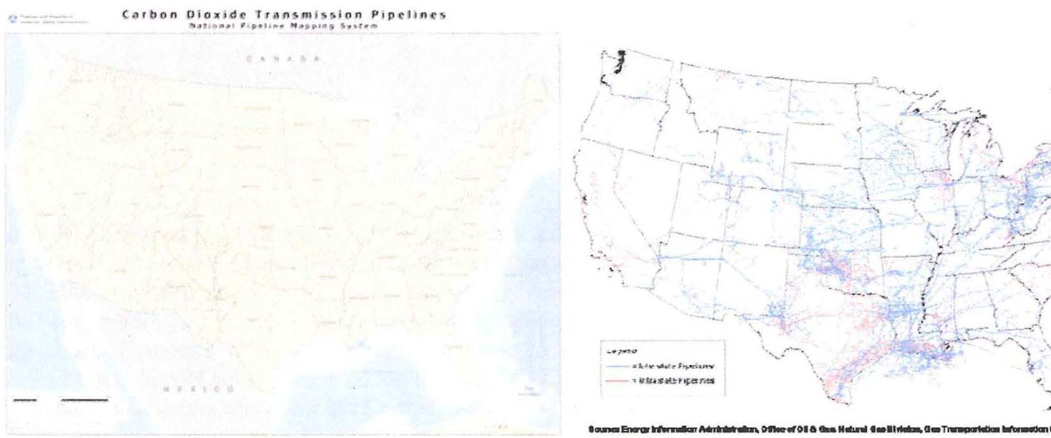

Figure 1: Existing U.S. CO_2 Pipelines (left-hand panel, [2]) and Existing U.S. Interstate and Intrastate Natural Gas Transmission Pipelines (left-hand panel, [3])

2. The Existing U.S. CO_2 Pipeline System

There are currently 3900 miles of dedicated CO_2 pipelines in the United States—of varying lengths and diameters—built primarily to serve CO_2-driven enhanced oil recovery (EOR) projects. Many of these pipelines deliver CO_2 from large natural underground accumulations, while some originate at anthropogenic sources (e.g., natural gas and syngas processing facilities). Eighty percent of the existing CO_2 pipeline infrastructure was built to deliver CO_2 into and within the Permian Basin of West Texas for the purpose of CO_2-driven EOR [4]. The earliest pipelines were built in the 1970s in Texas, where the first CO_2-floods were initiated. Other regions with significant CO_2 pipeline infrastructure include Wyoming/Colorado, Mississippi/Louisiana, Oklahoma, and North Dakota. The largest of the existing CO_2 pipelines is the 30-inch Cortez Pipeline, which was completed in 1983 and runs for slightly more than 500 miles from the McElmo Dome in Southwestern Colorado to the EOR fields in West Texas [5].

Nearly three-fourths of this existing CO_2 pipeline infrastructure was built in the 1980s and 1990s, largely driven by energy security concerns and resulting federal tax incentives designed to boost domestic oil production. In the 1980s, the major impetus for development was provided by significant changes to the Windfall Profits Tax that preferentially benefited EOR projects (taxed at 30 percent) over conventional oil production (taxed at 70 percent).

During the relatively short period of 1980–1985, major U.S. oil companies paid over \$88.5 billion (in constant 2005 dollars) in Windfall Profits Taxes [6]. While CO_2-driven EOR oil production was a relatively minor source of domestic oil production at that time, this change in the Windfall Profits Tax was a significant incentive for the commercial development of the large natural CO_2 deposits (domes) as well as the construction of the CO_2 pipeline infrastructure that continues to supply most of the CO_2 used for EOR in West Texas, Mississippi, and Louisiana [7]. These infrastructures, which were being developed in the 1980s, allowed for the quick adoption and expansion of the CO_2-EOR production method in the 1990s [8].[2]

Since 1990, the most significant federal incentive for CO_2-driven EOR stems from the Section 43 Enhanced Oil Recovery Tax Credit, which was enacted as a result of the Gulf War and renewed domestic concerns about energy security. The Section 43 tax credit can be applied to 15 percent of the capital costs in starting up a qualified EOR project and capital improvements to an operational flood. Perhaps most importantly, the credit is applicable to CO_2 purchases (IRS 2005 [9] describes allowable costs in detail). Over the period 1994–2005,[3] an estimated \$1.3 to \$1.9 billion (in constant 2005 dollars) in tax credits related to CO_2-driven EOR have been granted by the U.S. Internal Revenue Service.[4] This estimated \$1.3 to \$1.9 billion outlay is only the cost to the federal government and does not include state tax credits designed to boost domestic oil production through EOR.[5]

3. Drivers for an Expanded U.S. CO_2 Pipeline Infrastructure

The existing pipelines built to deliver CO_2 to aging oilfields for EOR may provide a starting point for an expanded national CO_2 pipeline system. Nonetheless, a key determinant governing the necessary size of a future U.S. CO_2 pipeline network is the proximity of each large industrial facility that will utilize CCS technologies (e.g., power plants, refineries) to suitable deep geologic storage reservoirs. For the United States—because of the numerous large and geographically well-distributed deep geologic CO_2 storage reservoirs—fully 95 percent of the largest CO_2 point sources lie within 50 miles of a potential storage reservoir [10]. It is, therefore, difficult to envision the need for long transcontinental CO_2 pipelines at the scale routinely built and operated to move oil and natural gas from relatively isolated pockets of production or import (e.g., Alaska, Gulf Coast) to distant and dispersed markets.

However, the overriding determinant of the extent of future growth of the nation's pipeline-based CO_2 transportation infrastructure will be the stringency and rate of implementation of future climate policy coupled with the cost competitiveness of CCS-derived emission reductions. Although many potential climate policies are debated in the United States, this analysis will focus on the impact of hypothetical future U.S. climate policies that follow the WRE450 and WRE550 stabilization pathways [11]. Since their original publication, these WRE pathways have become widely used benchmarks of requirements to stabilize atmospheric concentrations of greenhouse gases in an economically efficient manner [12]. The WRE450 and WRE550 climate policies are also useful for the present analysis as the range of costs of complying with these hypothetical policies bound much of the proposed climate legislation actively being considered in the U.S. Congress [13]. Thus, these WRE pathways can shed light on the potential scale of CCS deployment within the United States. The marginal cost of reducing greenhouse gas emissions is represented here as a price on CO_2 emissions to the atmosphere. This carbon permit price rises rapidly in the WRE450 case, reaching \$29/tonCO_2 by 2020, \$64/tonCO_2 by 2035, and \$140/ton CO_2 by 2050. In the WRE550 case, carbon permit prices increase more slowly, but these prices are still sufficient to send a powerful

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[2] During the early 1980s, CO_2 floods comprised a relatively minor aspect (approximately 5%) of total U.S. EOR production (with steam flooding the most commonly applied method). However, by 1990 CO_2-driven EOR accounted for approximately 15% of all EOR production[8].

[3] The Enhanced Oil Recovery Tax Credit was not available for tax years 2006 and 2007 because the price of oil was sufficiently high that the tax credit was completely phased out (See IRS 2007 [15] for further details).

[4] The IRS Statement of Income "Table 21 - Returns of Active Corporations, Other Than Forms 1120-REIT, 1120-RIC, and 1120S" reports data for the cost of the Enhanced Oil Recovery tax credit for the years 1994-2005 (http://www.irs.gov/taxstats/article/0,,id=170734,00.html). As this IRS publication does not specifically break out tax credits for CO_2-driven EOR from other approved EOR methods (e.g., steam flooding), historical data from the Oil and Gas Journal's biennial EOR Survey were used to compute what fraction of EOR in the U.S. is specifically CO_2-driven for each reported year [17]. The authors used these ratios to apportion the reported aggregate Section 29 tax credit expenditures into estimates for CO_2-driven EOR and all other approved methods, over this time period.

[5] Martin [8] lists a number of state tax incentives for CO_2-EOR and other secondary and tertiary enhanced oil recovery methods.

signal to the economy to begin decarbonising: \$5/tonCO_2 by 2020, \$10/tonCO_2 by 2035, and \$21/ton CO_2 by 2050. In both cases, carbon permit prices continue to increase after 2050, and investment decisions made before 2050 take this into account (CO_2 permit prices taken from Edmonds et al. [14]).

Figure 2 illustrates the resulting commercial adoption of CCS technologies by the U.S. electric utility sector in response to these two hypothetical climate policies. Figure 3 shows the resulting CO_2 pipeline infrastructure requirements under each scenario.

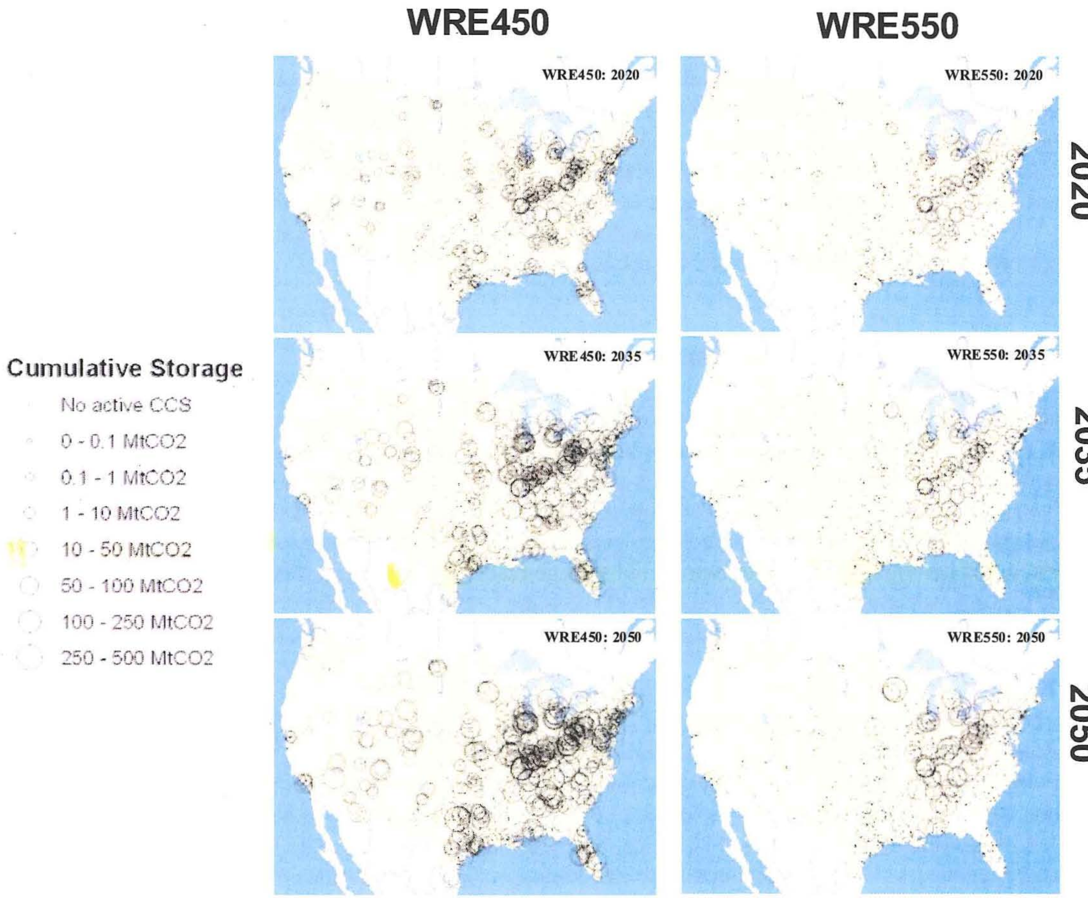

Figure 2: U.S. electric utility deployment of CCS-enabled generation systems under WRE450 and WRE550 hypothetical climate policies (Figure from Dooley et al. [15])

4. Estimating the Scale of a Future U.S. CO_2 Pipeline System

4.1. WRE450

In the more-stringent WRE450 stabilization case, up to 23,000 miles of dedicated CO_2 pipelines must be built and operated in the U.S. between 2010 and 2050. If implemented, a hypothetical stabilization policy such as this could result in approximately 54 $GtCO_2$ of CO_2 being captured and stored in deep geologic reservoirs by 2050. Adoption of CCS technologies at this pace and on this scale (along with continued expansion of renewables and nuclear power) would result in a nearly complete decarbonization of the U.S. electricity sector by the middle of this century (See Dooley et al. [14] for more details on these scenarios). It is important to realize that the projected 23,000 miles of new CO_2 pipeline would be built incrementally over time as the commercial deployment of CCS systems accelerates in response to the rising CO_2 permit price. Thus, only about 25 percent of the total projected 23,000 miles of CO_2 pipeline must be built before 2030 under this hypothetical WRE450 scenario.

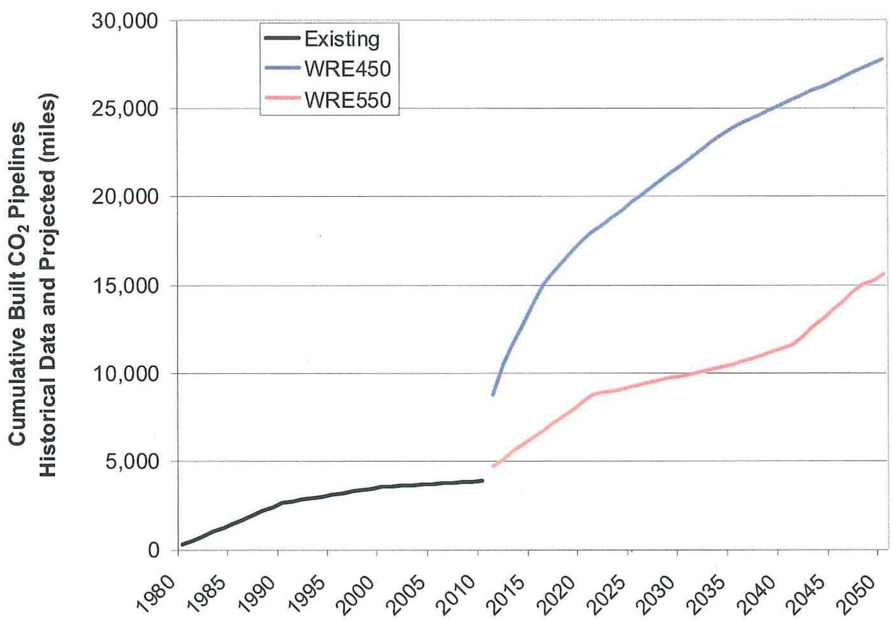

Figure 3: Projected commercial adoption of CCS technologies by the U.S. electric utility sector in response to WRE450 and WRE550 climate stabilization policies

4.2. WRE550

In the less-stringent WRE550 stabilization case, an estimated 11,000 miles of dedicated CO_2 pipeline must be added to the existing CO_2 pipeline system between 2010 and 2050. While less stringent than the WRE450 scenario, this hypothetical climate policy results in significant reductions in greenhouse gas emissions—due in part to significant commercial adoption of CCS technologies across the U.S. economy. For example, in this WRE550 scenario, the U.S. electric power sector's adoption of CCS technologies could result in approximately 19 $GtCO_2$ being stored in deep geologic formations by 2050. Again, this build-up of the CO_2 pipeline network unfolds over time in response to the escalating price of CO_2 emissions permits. In the near term (2010–2030), the growth in the CO_2 pipeline infrastructure across the U.S. economy under the WRE550 scenario equates approximately to a doubling of the current CO_2 pipeline system. Table 1 summarizes key data on the build-out of the national CO_2 pipeline system under the hypothetical WRE450 and WRE550 climate policies.

5. Discussion

While the size of these future CO_2 pipeline infrastructures may seem large, it is important to put the potential demand for CO_2 pipelines in some context. Since 1950, more than 270,000 miles of large inter- and intrastate natural gas pipeline were constructed in the United States to move natural gas from areas of production and/or importation to markets across the country (see Figure 1, left-hand panel).[6] This is an intentionally narrow accounting of the size of the nation's total liquid and natural gas hydrocarbon pipeline distribution system and is

---

[6] All data presented here on existing U.S. pipeline infrastructures are derived from USDOT [4].

intended to account only for those aspects of the pipeline infrastructure that would be most analogous to those used for CO_2 transport.[7]

Table 1: Summary Statistics of potential build-out of the U.S. CO_2 pipeline system 2010–2050 in response to WRE450 and WRE550 climate stabilization policies

	WRE 450 Stabilization	**WRE 550 Stabilization**
Average annual number of power plants adopting CCS 2010–2030	~ dozen per year	1–3 per year
CCS Adoption by high-purity CO_2 point sources 2010–2030[8]	(nearly) all high-purity CO_2 point sources decarbonized within 10 years	(relatively) slower adoption of CCS by high-purity CO_2 point sources
Average growth in CO_2 pipelines 2010–2030	<900 miles/year	~ 300 miles/year
Average source-sink pipeline length	Tens of miles	Tens of miles
CO_2 Pipelines in Operation 2030	~22,000 miles	<10,000 miles (i.e., approximately a doubling of the existing CO_2 pipeline system)
CO_2 Pipelines in Operation 2050	~28,000 miles	~16,000 miles

Since 1950, the U.S. economy has developed and maintained a natural gas pipeline transmission system that is *significantly* larger than the total amount of CO_2 pipeline that must be built in the 40-year period, 2010–2050, under the more-stringent WRE450 case. It is also important to note that the U.S. economy, as measured by its gross domestic product (GDP), has grown and is expected to continue growing in the future. Between 1950 and 2000, the U.S. GDP grew from \$2 to \$11 trillion dollars (in constant 2005 US\$). Between 2010 and 2050, the U.S. GDP is projected to double from approximately \$13 to \$26 trillion (in constant 2005 US\$). In this regard, it is particularly noteworthy that in both the 1950s and 1960s, with a much smaller economy than exists today or that might exist between now and mid-century, more than 100,000 miles of these large natural gas transmission pipelines were built without disruption of the nation's energy infrastructure or macroeconomy.

In both the WRE450 and WRE550 cases modelled here (Figure 4), a handful to a dozen large power plants and other industrial facilities are expected to adopt CCS systems each year, demanding between a few hundred and a few thousand miles of new pipeline constructed per year. Given the scale of the existing natural gas transmission pipeline network and given that much of it was built in a relatively short period during a time that the U.S. economy was significantly smaller, the cost burden imposed by the need to build a CO_2 pipeline infrastructure should not pose a significant barrier for the commercial deployment of CCS systems in the United States.

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[7] This estimate does not include the more than 900,000 miles of natural gas distribution pipeline mains built since 1950 that move natural gas from these large transmission lines into communities nor does it include smaller natural gas pipelines that would be needed to move natural gas "the last mile" to its final point of consumption (e.g., a home, factory, or commercial building).

[8] There are approximately 350 "high purity" stationary CO_2 point sources in the U.S. These tend to be smaller facilities and therefore they account for only about 6% of the emissions from large stationary CO_2 point sources (large is defined here as more than 100,000 tonsCO_2/year). These high purity CO_2 point sources include natural gas processing, ethanol, ammonia, ethylene oxide facilities). See Dooley et. al. 2007 for further details.

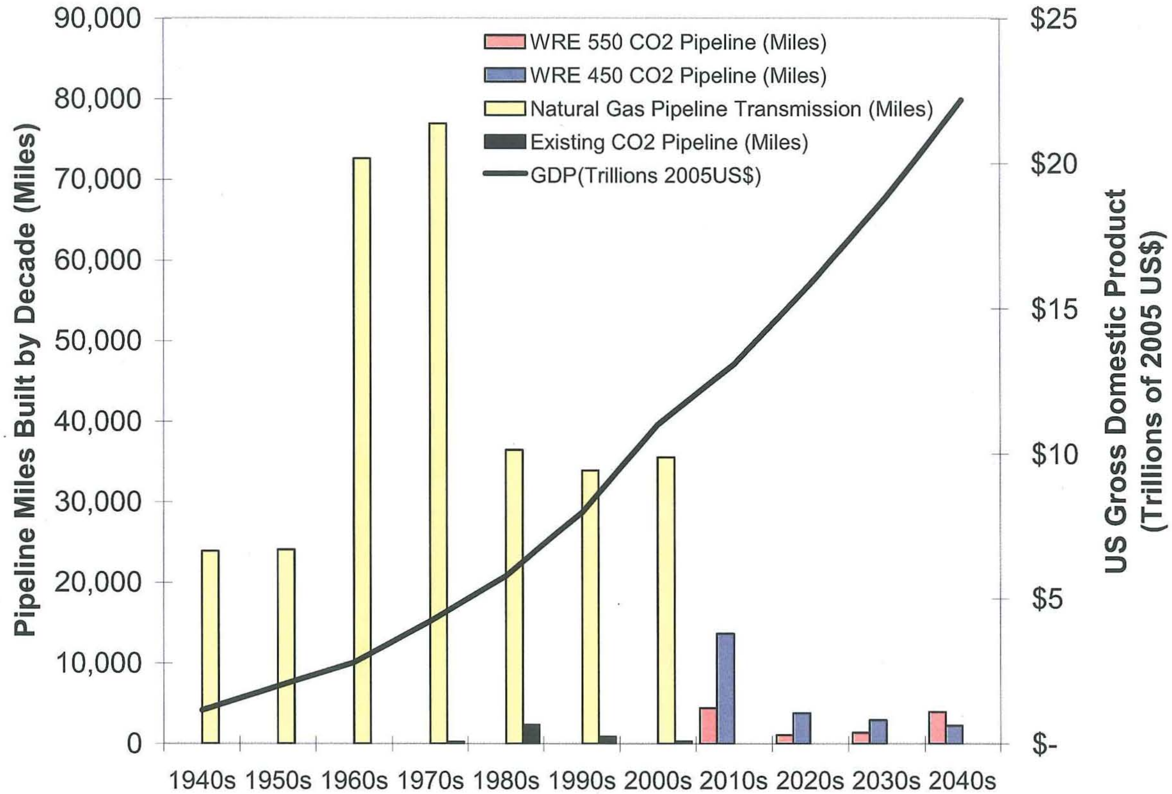

Figure 4: Growth in selected U.S. pipeline systems since 1950 as well as projections of growth in a dedicated CO_2 pipeline system between 2010–2050 as well as U.S. GDP 1950–2050

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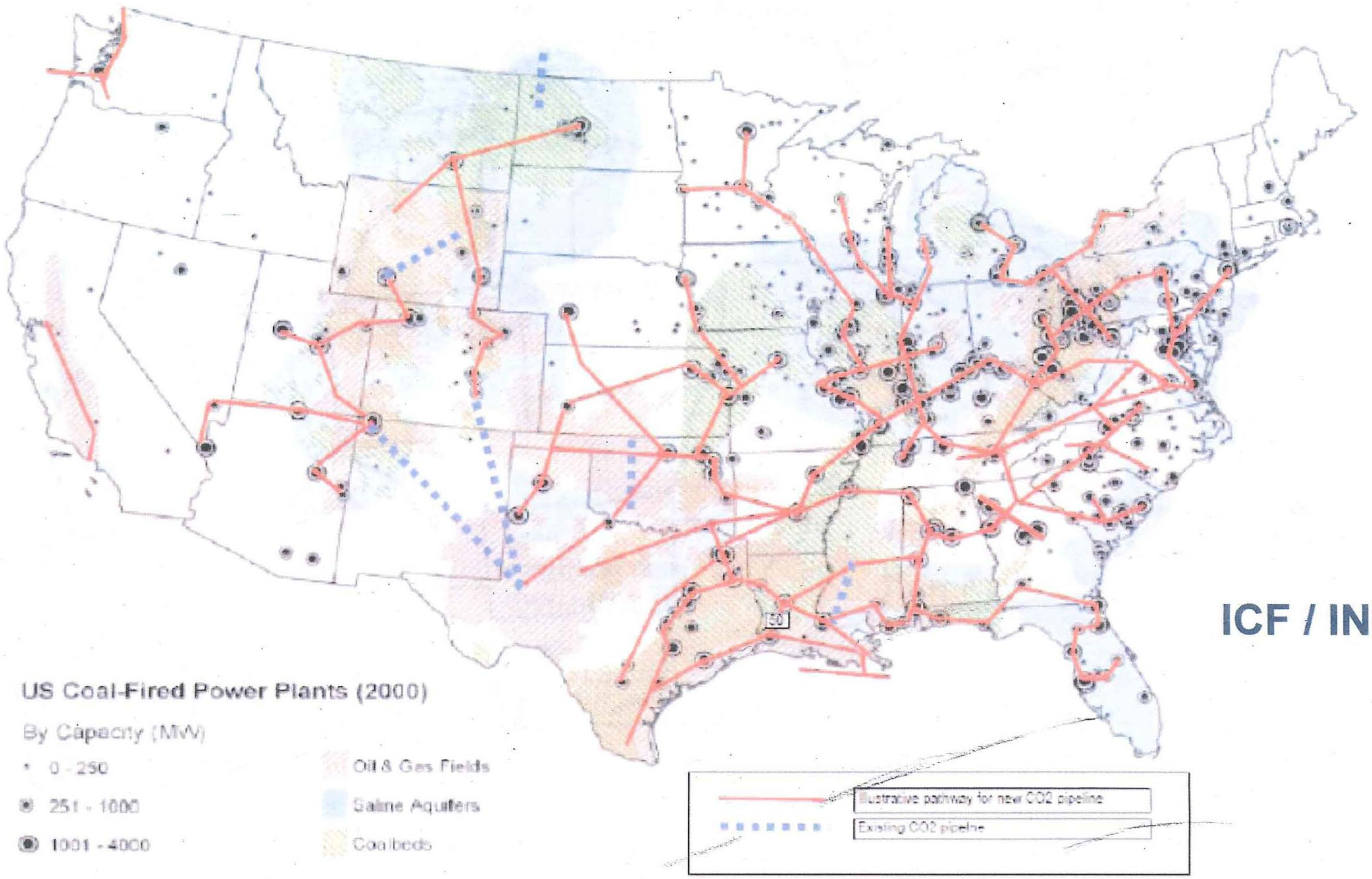
Figure 4-2 Map of Possible CO_2 Pipeline Corridors for High CCS Case with Greater Use of EOR



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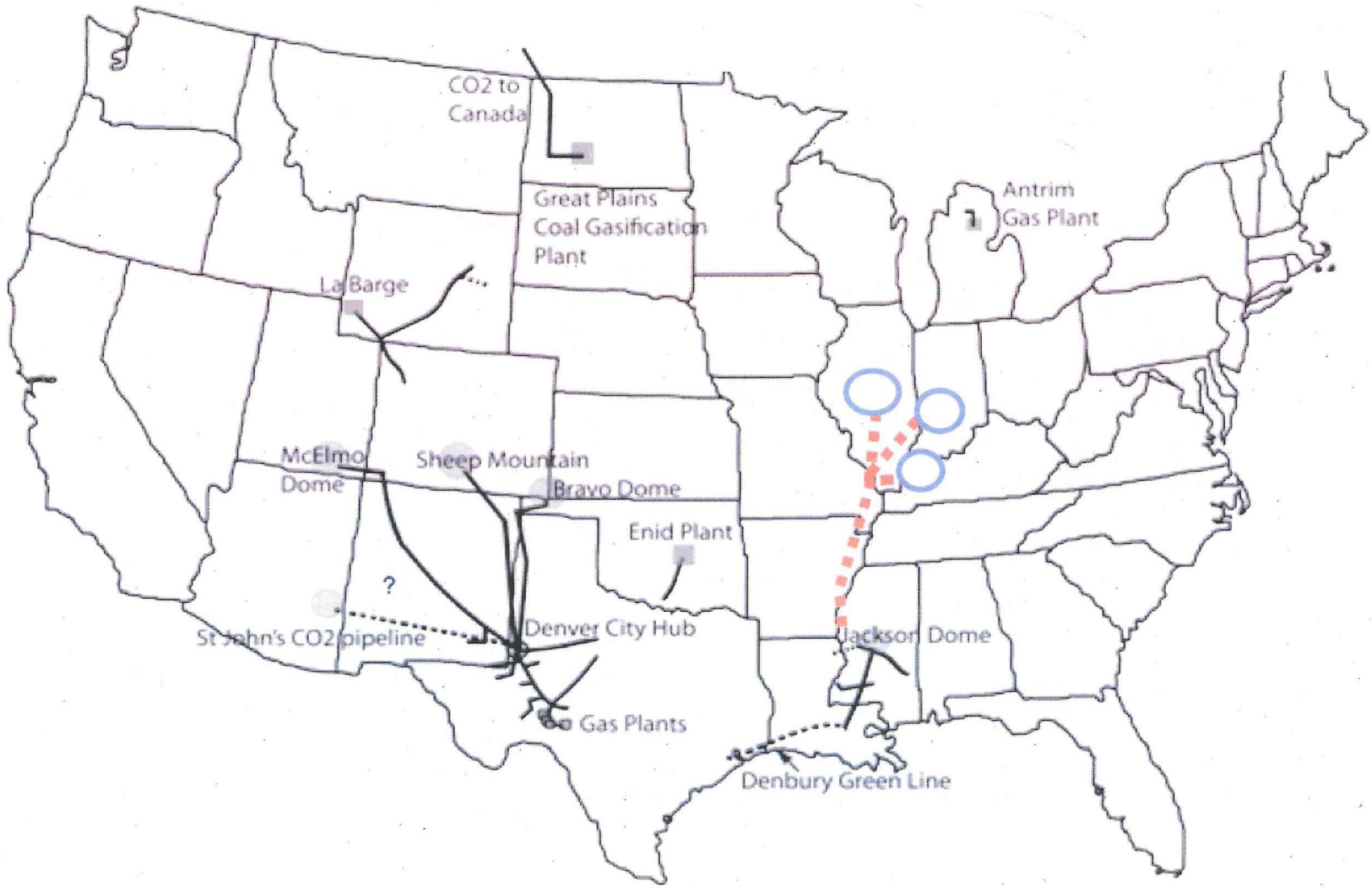
U.S. CO2 Pipelines & Midwest Pipeline Expansion Project



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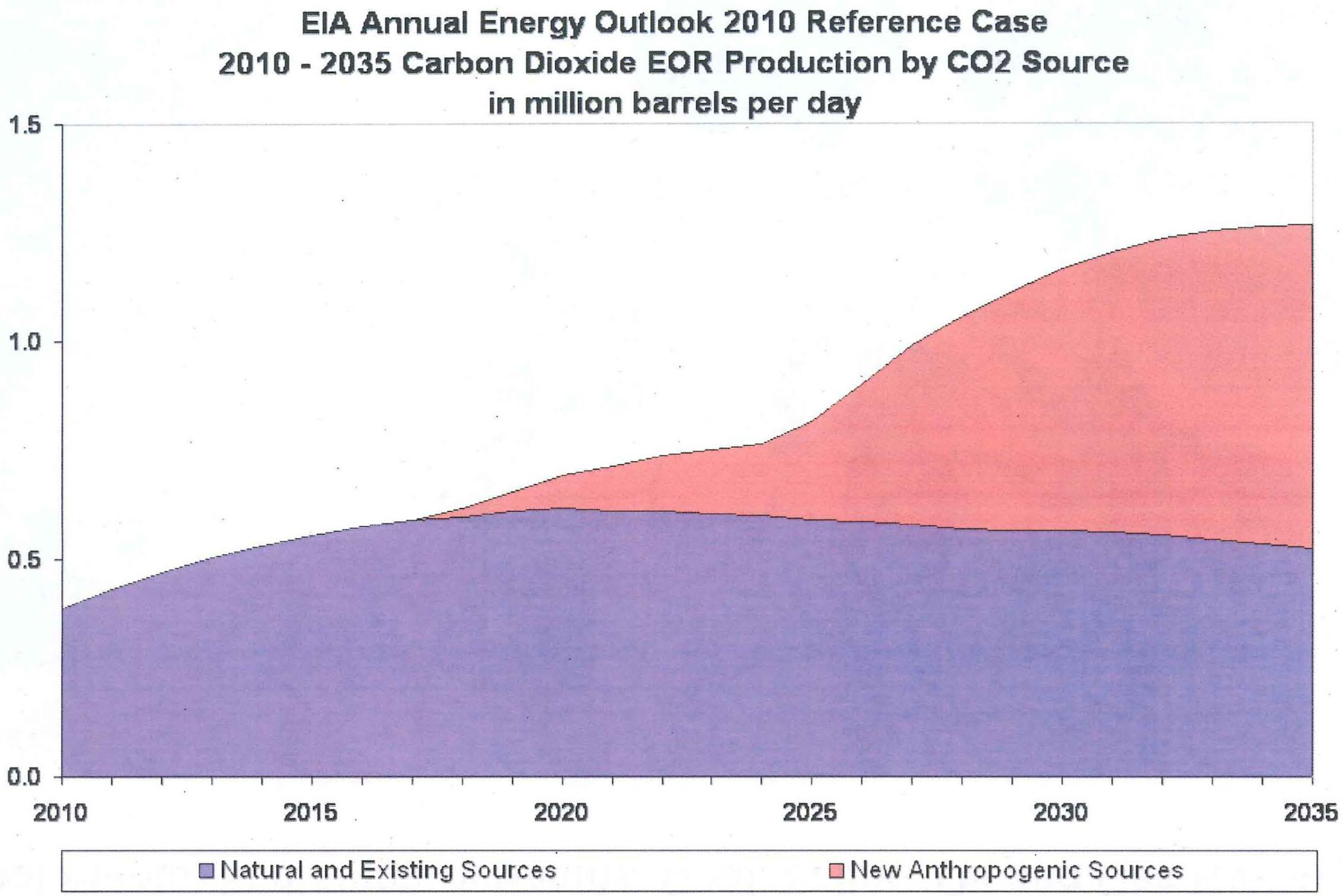
Future EOR Will Require Substantial Volumes of Captured CO2



Source: National Petroleum Council 2011

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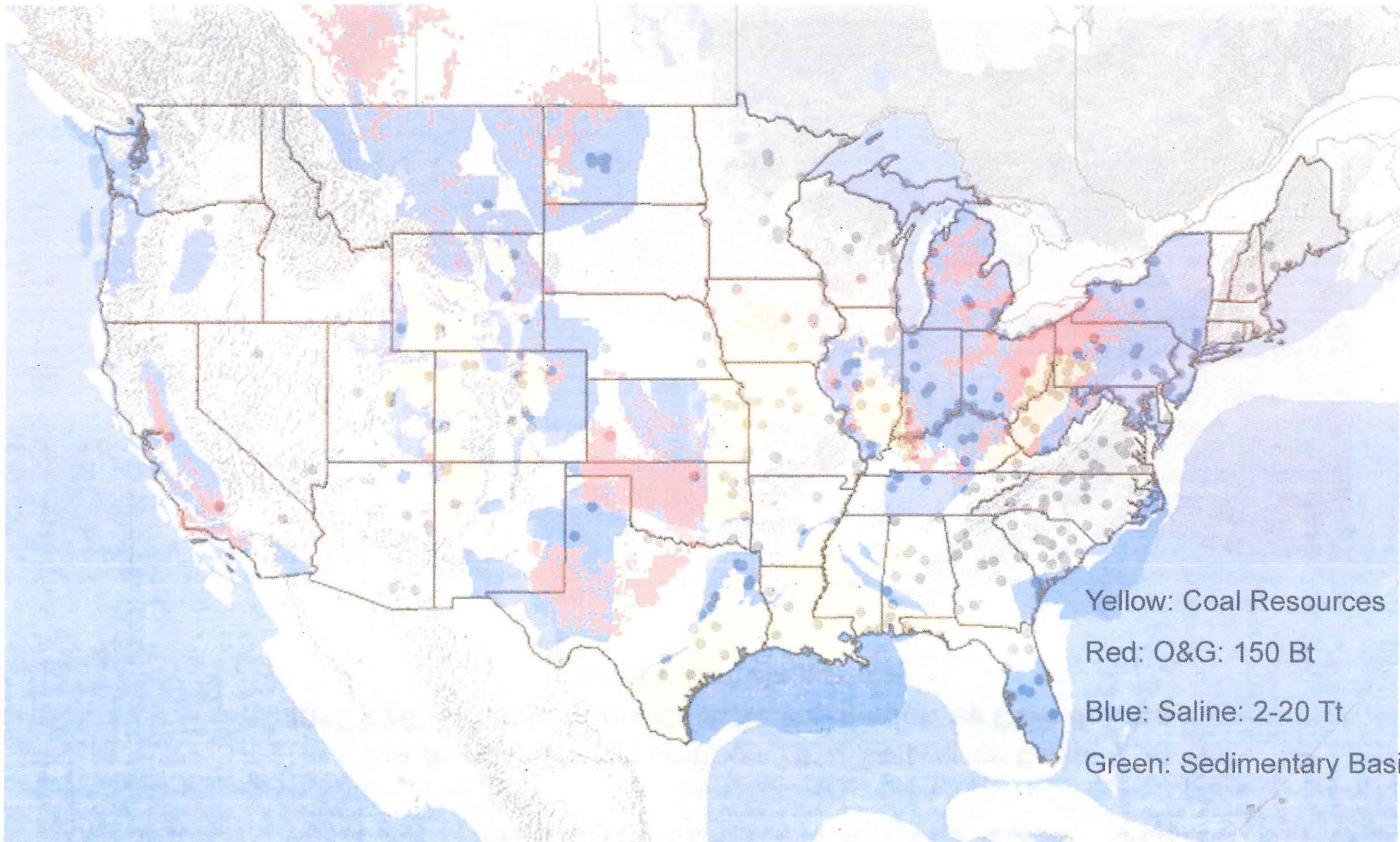
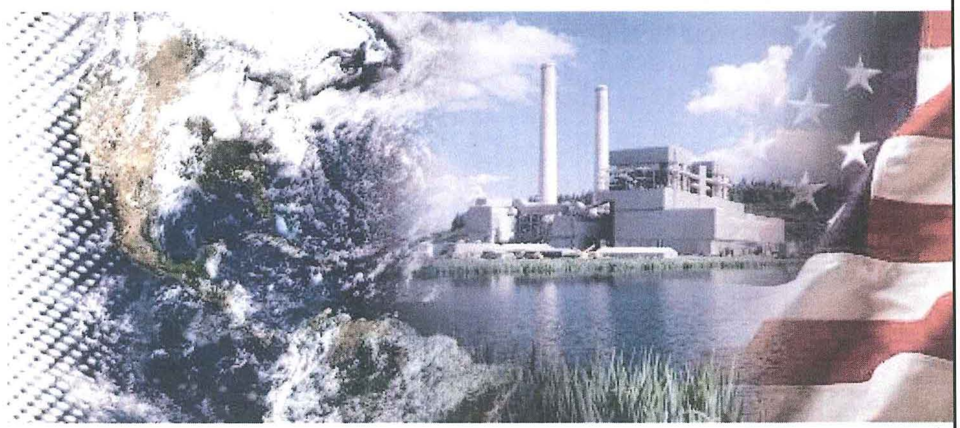
Coal Plants, Sedimentary Basins, Coal, Saline, Oil and Gas Resources



Base map generated on NATCARB Viewer: http://www.natcarbviewer.com/

NATIONAL ENERGY TECHNOLOGY LABORATORY



Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR)

June 20, 2011

DOE/NETL-2011/1504
Activity 04001.420.02.03

U.S. DEPARTMENT OF ENERGY

Disclaimer

"Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR)"

Activity 04001.420.02.03

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I. EXECUTIVE SUMMARY

This analysis, sponsored by U.S. DOE/NETL and prepared by Advanced Resources International (ARI), builds a national CO_2 EOR resource assessment from reservoir-to-reservoir simulations of CO_2 floods. ARI used a proprietary database that contains oil properties and geologic characteristics of 1,800 onshore reservoirs and over 4,000 off shore sands. The simulations were conducted using the PROPHET model. PROPHET, originally developed by Texaco for DOE in the 1980s, models stream tubes of fluid flow between injection wells and producing wells. PROPHET is a screening tool and estimates the magnitude and timing of oil production based on a user-defined CO_2 injection protocol and the porosity of the host rock, the thickness of the oil, the degree of fracturing and discontinuity within the target formation and other inputs. NETL published a similar resource assessment in February 2010; this report supersedes the earlier assessment. For this analysis, the simulation methodology was peer reviewed by industry practitioners and important refinements were made based on their input. Aggregated results indicate that CO_2-EOR can provide high value benefits to the domestic economy and the environment, as discussed below.

1. CO_2-EOR Promotes Enhanced Energy Security and Lower CO_2 Emissions

Increasing U.S. oil production and lowering domestic CO_2 emissions are two of the nation's highest priority goals. CO_2 enhanced oil recovery (CO_2-EOR), both as practiced today ("State of Art" (SOA)) and what is possible ("Next Generation"), directly addresses these two goals.

- "Next Generation" CO_2-EOR can provide 137 billion barrels of additional technically recoverable domestic oil, with about half (67 billion barrels) economically recoverable at an oil price of $85 per barrel.[1] Technical CO_2 storage capacity offered by CO_2-EOR would equal 45 billion metric tons.

- This volume of economically recoverable oil is sufficient to support nearly 4 million barrels per day of domestic oil production (1.35 billion barrels per year for 50 years), reducing oil imports by one-third. Production of oil from the ROZ (residual oil zone) would add to these totals.

- Nearly 20 billion metric tons of CO_2 will need to be purchased by CO_2-EOR operators to recover the 67 billion barrels of economically recoverable oil. Of this, about 2 billion metric tons would be from natural sources and currently operating natural gas processing plants. The remainder of the CO_2 demand (18 billion metric tons) would need to be provided by anthropogenic CO_2 captured from coal-fired power plants and other industrial sources.

- The market for captured CO_2 emissions from power plants created by economically feasible CO_2-EOR projects (projects that provide at least 20% ROR at an oil price of $85 per barrel and a CO_2 cost of $40 per metric ton) would be sufficient to permanently store the CO_2 emissions from 93 large one GW size coal-fired power plants operated for 30 years.

[1] In addition to an oil price of $85 per barrel (WTI), the economic analysis assumes a CO_2 market price of $40 per metric ton and a 20% return on investment, before tax.

2. *CO_2-EOR Can Provide Large New Revenues to Federal/State Treasuries and Other Participants in the Value Chain.*

The value created by applying "Next Generation" CO_2-EOR technology would be shared by numerous stakeholders. Assuming an oil price of $85 per barrel (WTI) and a CO_2 market price of $40 per metric ton, the following new revenue streams would result from recovering 67.2 billion barrels of domestic oil with "Next Generation" CO_2-EOR technology:

- Federal/state treasuries would be a large beneficiary, receiving $21.20 of the $85 per barrel oil price in the form of royalties on Federal /state lands plus severance, ad valorem and corporate income taxes. Total revenues to Federal/state treasuries would equal $1,420 billion.
- Electric power and other industrial companies would receive $10.80 of the $85 per barrel oil price from the sale of CO_2. Total revenues from sale of CO_2 at $40 per metric ton would equal $730 billion.
- The U.S. oil industry would receive $19.50 of the $85 per barrel oil price for return of and return on capital investment. Private mineral owners would receive $7.70 per barrel.
- The general U.S. economy would be the largest beneficiary, receiving $25.80 of the $85 per barrel of oil price, in the form of wages and material purchases. Total revenues would equal $1,730 billion.

With potential oil recovery of 67.2 billion barrels, $5.7 trillion of new domestic revenues and economic activity would accrue to the participants in the CO_2-EOR value chain.

Table EX-1. Distribution of Revenues from "Next Generation" CO_2-EOR

Revenue Recipient	Value Chain Function	Revenues Per Barrel ($)	Revenues TOTAL ($ billion)
1. Federal/State Treasuries	Severance/Income Taxes	$21.20	$1,420
2. Power/Industrial Companies	Sale of Captured CO_2 Emissions	$10.80	$730
3. Oil Industry	Return of/on Capital	$19.50	$1,300
4. Other	Private Mineral Rights	$7.70	$520
5. U.S. Economy	Services, Materials and Sale of CO_2	$25.80	$1,730
	Total	**$85.00**	**$5,700**

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3. The Volumes of Oil Recovery and CO_2 Storage Offered by "Next Generation" CO_2-EOR are Large and Impressive.

With active use of "Next Generation" CO_2-EOR technology, large volumes of domestic oil could be produced while similarly large volumes of CO_2 could be reliably stored in domestic oil fields, Table EX-2:

Table EX-2. Oil Recovery and CO_2 Storage From "Next Generation" CO_2-EOR Technology

Reservoir Setting	Oil Recovery** (Billion Barrels)		CO_2 Demand/Storage** (Million Metric Tons)	
	Technical	**Economic***	**Technical**	**Economic***
1. Miscible CO_2-EOR				
Lower-48 Onshore	104.4	60.3	32,250	17,230
Alaska	8.8	5.7	4,110	2,330
Offshore	6.0	0.9	1,770	260
Sub-Total	**119.1**	**67.0**	**38,130**	**19,820**
2. Near Miscible CO_2-EOR	**1.2**	**0.2**	**800**	**110**
3. Residual Oil Zone***	16.3	n/a	6,500	n/a
TOTAL	**136.6**	**67.2**	**45,430**	**19,930**

*At $85 per barrel oil price and $40 per metric ton of CO_2 market price with ROR of 20% (before tax). JAF2011_030.XLS

**Includes 2.6 billion barrels already produced or being developed with miscible CO_2-EOR and 2,300 million metric tons of CO_2 from natural sources and gas processing plants.

***ROZ resources below existing oil fields in three basins; economics of ROZ resources were beyond study scope.

- The volumes of domestic oil technically recoverable with "Next Generation" CO_2-EOR technology are large: 120.3 billion barrels from the main pay zone of oil fields plus another 16.3 billion barrels from the Residual Oil Zone (ROZ).
- With an oil price of $85 per barrel and a CO_2 cost of $40 per metric ton, over 67 billion barrels will be recoverable (with ROR of 20%). An economic evaluation of oil recovery from ROZs would add to this total. As a point of reference, proved domestic oil reserves at the end of 2009 were 21 billion barrels.
- The volumes of CO_2 that could be technically stored with EOR are equally large--over 45 billion metric tons. These volumes would significantly increase as the storage potential offered by the ROZ "fairways" becomes better defined. As a point of reference, annual CO_2 emissions from domestic coal and natural gas-fired electricity production in 2009 were 2.2 billion metric tons.
- Assuming about 2 billion metric tons of CO_2 are provided to the CO_2-EOR industry from natural sources and gas processing plants, almost 18 billion metric tons of anthropogenic CO_2 could be sold to the CO_2-EOR market.

4. *"Next Generation" CO_2-EOR Provides Benefits Far Beyond Those Available from State of Art CO_2-EOR.*

The introduction of "Next Generation" CO_2-EOR technology would provide significant oil recovery and CO_2 storage benefits beyond those available from today's state of art (SOA) CO_2-EOR technology, Table EX-3:

Table EX-3. Comparison of Technically and Economically Recoverable Domestic Oil and CO_2 Storage Capacity from State of Art (SOA) and "Next Generation" CO_2-EOR Technology*

Basin/Area	Technically Recoverable Oil (Billion Barrels)		Economically Recoverable Oil** (Billion Barrels)		Economic CO_2 Demand/Storage** (Million Metric Tons)	
	SOA	"Next Generation"	SOA**	"Next** Generation"	SOA**	"Next Generation"
1. Miscible CO2-EOR						
Lower-48 Onshore	55.7	104.4	24.3	60.3	8,940	17,230
Alaska	5.8	8.8	2.6	5.7	1,490	2,330
Offshore GOM	-	6.0	-	0.9	-	260
Sub-Total	**61.5**	**119.1**	**26.9**	**67.0**	**10,430**	**19,820**
2. New Miscible CO2-EOR	**n/a**	**1.2**	**n/a**	**0.2**	-	**110**
3. Residual Oil Zones	**n/a**	**16.3**	**n/a**	***	-	***
Total	**61.5**	**136.6**	**26.9**	**67.2**	**10,430**	**19,930**

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*Includes 2.6 billion barrels already produced or placed into reserves with miscible CO_2-EOR and 2,300 million metric tons of CO_2 from natural sources and gas processing plants.

**At an oil price of $85 per barrel and a CO_2 cost of $40 per metric ton with ROR at 20% before tax.

***The economics of recovering oil from the residual oil zone were beyond study scope.

- The volumes of technically recoverable domestic oil would more than double, from 62 billion barrels with SOA technology to 137 billion barrels with "Next Generation" CO_2-EOR technology.
- Economically recoverable domestic oil would increase even more substantially, to 67 billion barrels with "Next Generation" technology compared to 27 billion barrels with SOA technology.
- The volumes of economically driven CO_2 demand by the CO_2-EOR industry would climb to nearly 20 billion metric tons from "Next Generation" technology. With about 2 billion metric tons of CO_2 provided by natural sources and gas processing plants, the net economic demand for CO_2 captured from power and industrial plants would be 18 billion metric tons (equal to 30 years of captured CO_2 emissions from 93 GWs of coal-fired power). SOA technology would create

a market demand for captured CO_2 of only about 8 billion metric tons (equal to 30 years of captured CO_2 emissions from 43 GWs of coal-fired power).[2]

5. *"Next Generation" CO_2-EOR Technologies Are Realistic and Achievable with Focused Investments in R&D.*

Before proceeding, it is useful to address the question - - just what constitutes "Next Generation" CO_2 enhanced oil recovery and how would it benefit the U.S. economy and energy security? Briefly stated, "Next Generation" CO_2-EOR incorporates four significant and, with investments in R&D plus field pilots, realistically achievable advances in technology:

- Improvements in currently practiced miscible CO_2-EOR technology,
- Advanced near miscible CO_2-EOR technology,
- Application of CO_2-EOR to residual oil zones (ROZs),[3,4,5] and
- Deployment of CO_2-EOR in offshore oil fields.

Chapter IV of the report provides a more in-depth look at these four "Next Generation" CO_2-EOR technologies. Chapter V of the report provides a more detailed explanation of the benefits of "Next Generation" CO_2-EOR technology.

The remainder of the report provides context, relevant information and details to help the reader better understand CO_2-EOR and its contribution toward improved domestic energy security and lower emissions of CO_2.

- Chapter II of the report discusses today's CO_2-EOR activities as well as its future promise under "Next Generation" technology.
- Chapter III of the report provides a case study of the evolution in CO_2-EOR practices and performance in the Permian Basin.
- Chapter VI provides a "basin-oriented" look at the applicability of CO_2-EOR in eleven U.S. basins and regions.
- Chapter VII provides an overview of the study methodology, which is more fully discussed in Appendix A.

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[2] Assuming 85% capacity factor and 34% efficiency, a1GW power plant would generate 223 billion kWh of electricity in thirty years (1GW x 85% x 8.76 (conversion between GW and billion kWh/year) * 30 years). With a CO_2 intensity of 0.94 million metric tons CO_2/kWh (thermodynamic equivalency based on efficiency of power plant and emissions profile of average coal) and 90% capture, this power plant would supply 189 million metric tons of CO_2 in 30 years, at 6.3 million metric tons per year.

[3] "Technical Oil Recovery Potential from Residual Oil Zones: Permian Basin", prepared by Advanced Resources International, Inc. for the U.S. Department of Energy, Office of Fossil Energy, Office of Oil and Natural Gas, October 2005.

[4] "Technical Oil Recovery Potential from Residual Oil Zones: Big Horn Basin", prepared by Advanced Resources International, Inc. for the U.S. Department of Energy, Office of Fossil Energy, Office of Oil and Natural Gas, February 2006.

[5] "Technical Oil Recovery Potential from Residual Oil Zones: Williston Basin", prepared by Advanced Resources International, Inc. for the U.S. Department of Energy, Office of Fossil Energy, Office of Oil and Natural Gas, February 2006.

* * * * *

This report represents a significant update of the "Next Generation" CO_2-EOR technology first introduced in DOE/NETL Report -2009/135 "Storing CO_2 and Producing Domestic Crude Oil with "Next Generation" CO_2-EOR". The following major changes have been made since the previous version:

- The economic and reservoir models employed in the analysis have been thoroughly vetted by industry experts and practitioners. Based on input from these stakeholders, Advanced Resources made adjustments to how CO_2-floods are evaluated by the *PROPHET2* model and how field and pattern economics are calculated in our cashflow models.
- The current version of the report employs a significantly updated reservoir data base, incorporating current data on many important reservoir datapoints, such as cumulative production, reserves and well counts, among others.
- The economic model in the current study incorporates an economic truncation function that limits the volumes of CO_2 injection (and project life) using a marginal annual economic calculation.
- To better capture current economic conditions, we have employed new oil and CO_2 prices. The "base case" economic scenario now uses an $85/Bbl oil price and a $40/metric ton CO_2 market price. Additionally, CO_2 market prices are now calculated as a percentage of oil price. To reflect historical practices, we model CO_2 market prices at 2% to 3% of oil price (in terms of $/Mcf of CO_2) in our sensitivity analysis section of the report.
- Finally, to recognize the higher risks of introducing an emerging technology, such as "Next Generation" CO_2-EOR and its need to compete for capital with other domestic energy investments, the economics have been evaluated using a 20% return on investment, compared to a 15% return on investment in the previous study.

Advanced Resources is truly grateful for industry's participation and input and has summarized the major recommendations we received and incorporated into this updated study in Appendix B.

II. THE CURRENT AND FUTURE PROMISE OF CO_2-ENHANCED OIL RECOVERY

A. The Current Status of CO_2-EOR

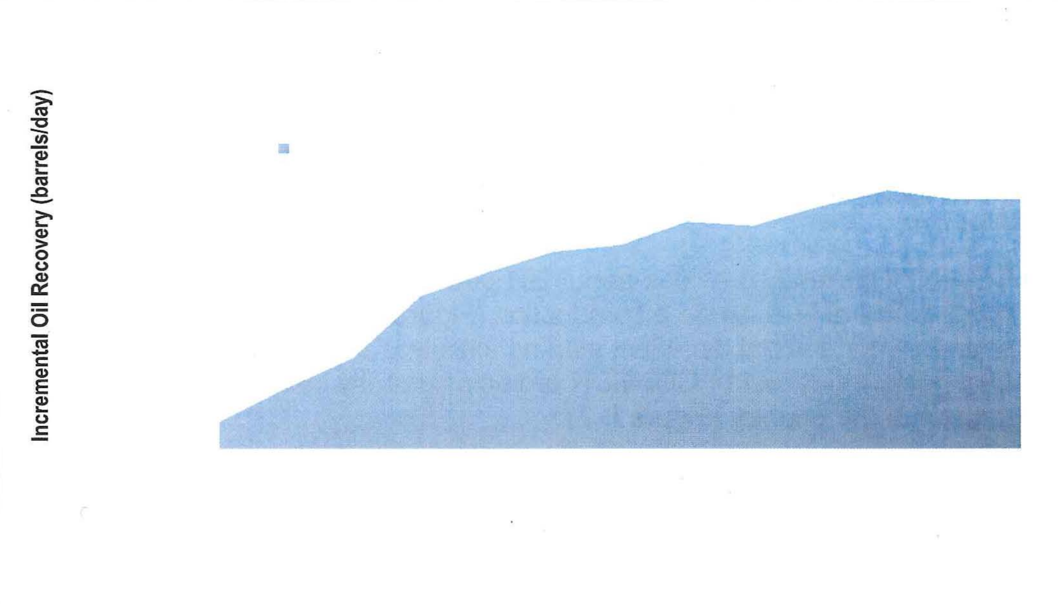
CO_2-based enhanced oil recovery, using State of Art (SOA) technology, is already being implemented, particularly in the oil fields of the Permian Basin of West Texas, the Gulf Coast and the Rockies.

- CO_2-EOR currently provides about 281,000 barrels of oil per day in the U.S.,[6] equal to 6% of U.S. crude oil production (Figure II-1). CO_2-EOR has been underway for several decades, starting initially in the Permian Basin and expanding today to 114 CO_2-EOR projects currently installed in numerous regions of the country (Figure II-2).
- Today, the great bulk of the CO_2 used for EOR comes from natural sources, such as McElmo Dome in New Mexico and Jackson Dome in Mississippi. These natural sources are supplemented by modest, but growing sources of anthropogenic CO_2 (Table II-1).
- A robust network of pipelines transport CO_2 from natural CO_2 deposits and gas processing plants to the Denver City Hub (Figure II-3). Still, the number one barrier to reaching higher levels of CO_2-EOR production is lack of access to adequate supplies of affordable CO_2.
- As shown in Table II-1, the largest single source of anthropogenic CO_2 used for EOR is the capture of 340 MMcfd (6.6 MMmt/yr) of CO_2 from the gas processing plant at La Barge in Western Wyoming. This is followed by the "poster child" for integrating large-scale CO_2-EOR with CCS - - the capture of 150 MMcfd (~3MMmt/yr) of CO_2 from the Northern Great Plains Gasification plant in Beulah, North Dakota and its transport, via a 200 mile cross-border CO_2 pipeline, to the two EOR projects at the Weyburn oil field in Saskatchewan, Canada.

New CO_2 pipelines and refurbished gas treating plants have recently been placed on-line (Figure II-2).[7] These include Denbury's 320 mile Green Pipeline along the Gulf Coast, and Occidental Petroleum's new $850 million Century natural gas/CO_2 processing plant and pipeline facilities in West Texas. The proposed Denbury (Encore) pipeline (linked to the Lost Cabin gas plant in Wyoming) is proposed to come on line as of late 2012. These new facilities will significantly expand the availability and use of CO_2 in domestic oil fields, leading to increased oil production from CO_2-EOR. For example, Occidental Petroleum expects the installation of the Century CO_2 plant to expand its Permian Basin oil production by 50,000 barrels per day within 5 years.[8]

[6] Oil and Gas Journal EOR Survey, April 2010.
[7] Various industry presentations and publications.
[8] Occidental Petroleum Investor Presentation, October, 2010.

Figure II-1. Growth CO_2-EOR Production in the U.S.



Source: Advanced Resources Int'l., based on Oil and Gas Journal, 2010.

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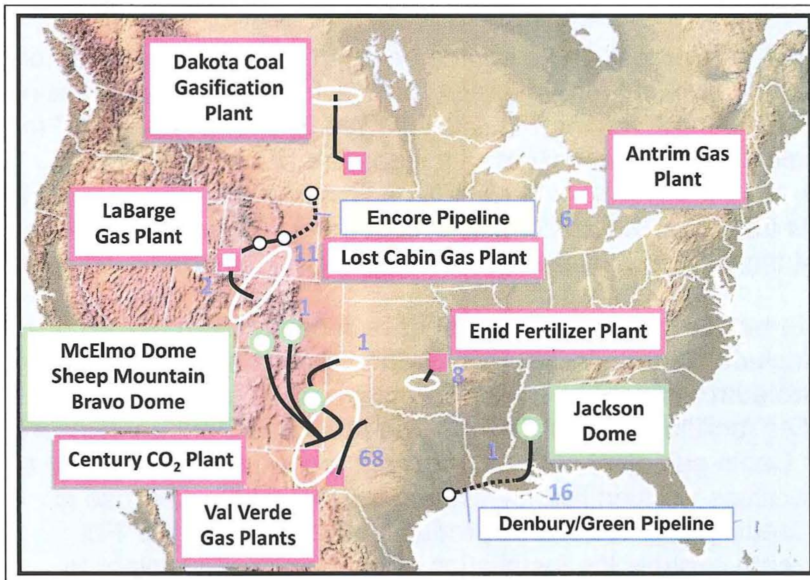
Figure II-2. Current U.S. CO_2-EOR Activity



- Currently, 114 CO_2-EOR projects provide 281,000 B/D.
- New CO_2 pipelines - - the 320 mile Green Pipeline, the 226 mile Encore Pipeline and the Century CO_2 Plant - - are expanding the use of CO_2-EOR.

Source: Advanced Resources International, Inc., based on Oil and Gas Journal, 2010 and other sources.

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Figure II-3. Existing CO_2 Pipelines (Permian Basin)

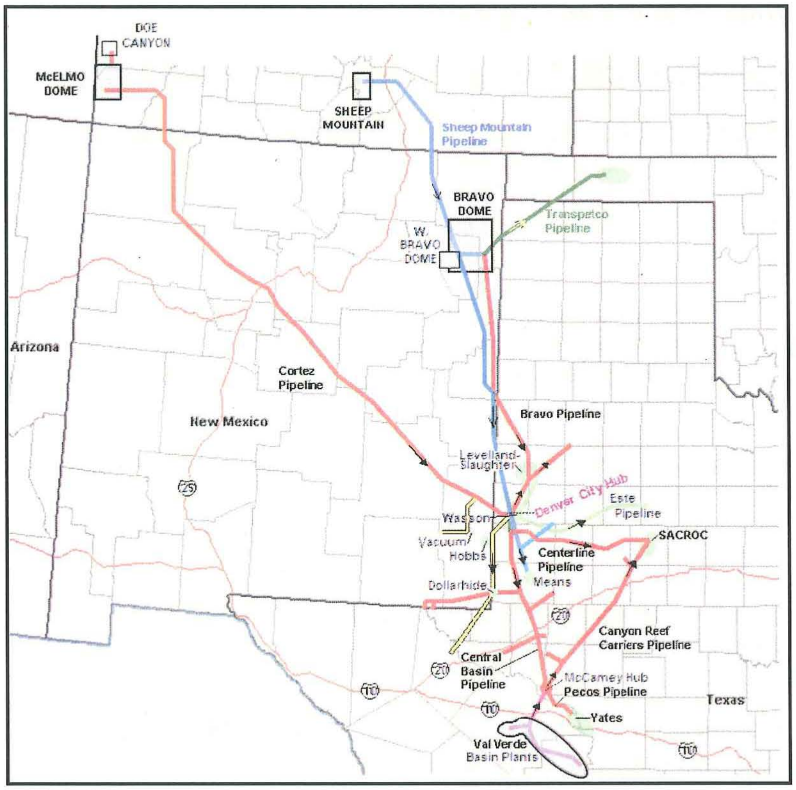

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Table II-1. Significant Volumes of Anthropogenic CO_2 Are Already Being Injected for EOR

Location of EOR / CO_2 Storage	CO_2 Sources by Type and Location	CO_2 Supply (MMcfd)*	
		Natural	Anthropogenic
Texas-Utah-New Mexico-Oklahoma	Natural CO_2 (Colorado-New Mexico)	1,730	335
New Mexico-Oklahoma	Gas Processing Plants (W. Texas)		
Colorado-Wyoming	Gas Processing Plants (Wyoming)	-	340
Mississippi/Louisiana	Natural CO_2 (Mississippi)	1,100	-
Michigan	Ammonia Plant (Michigan)	-	15
Oklahoma	Fertilizer Plant (Oklahoma)	-	30
Saskatchewan	Coal Gasification Plant (North Dakota)	-	150
TOTAL (MMcfd)		**2,830**	**870**
TOTAL (million mt/yr)**		**55**	**17**

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* Additional CO_2 supplies are anticipated in 2012 from the Lost Cabin gas processing plant in Wyoming (50 to 60 MMcfd) and from Train II of the Century gas processing plant in West Texas (180 MMcfd).
**MMcfd of CO_2 can be converted to million metric tons per year by first multiplying by 365 (days per year) and then dividing by 18.9 Mcf per metric ton.
Source: Advanced Resources Int'l (2011).

B. The Future Promise of CO_2-EOR

1. Oil Recovery and CO_2 Storage: Traditional ("Main") Pay Zone of Oil Fields.

The assessments of oil recovery and CO_2 storage capacity set forth in this report have been based on a database of over 6,300 domestic oil reservoirs, accounting for three-quarters of U.S. oil resources. The study identified 1,858 large oil reservoirs with 366 billion barrels of original oil in-place (487 billion barrels of original oil in-place when extrapolated to national totals) as favorable for CO_2-EOR.

These large oil reservoirs were modeled for CO_2–based enhanced oil recovery using ARI's adaptation of the streamline reservoir simulator *PROPHET2*. The amount of CO_2 storage capacity offered by oil fields favorable for CO_2-EOR was then evaluated using "Next Generation" CO_2-EOR technology and economics.

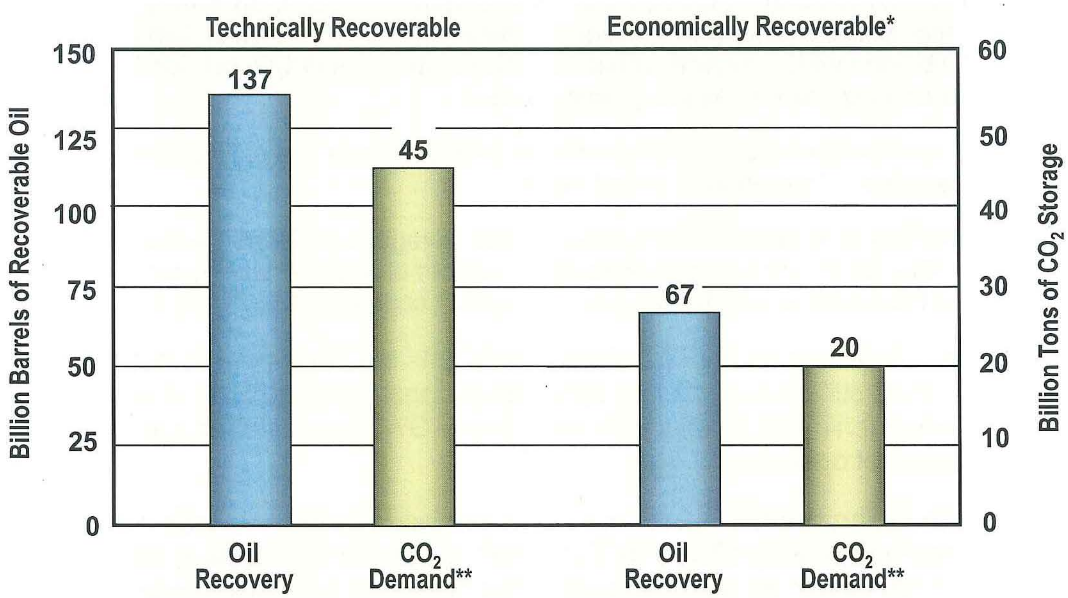
The study established two oil recovery and CO_2 storage categories -- "Technical Potential" (without consideration of prices and costs) and "Economic Potential" (the volume of oil the industry could produce and the volume of CO_2 industry could buy (and store) at a specified oil price and CO_2 market price).

As shown in Figure II-4, the volume of technically recoverable oil using "Next Generation" CO_2-EOR is 136.6 billion barrels. The CO_2 volume associated with this technically recoverable oil is 45.4 billion metric tons.

The volume of economically recoverable oil (at an oil price of $85/B, CO_2 costs of $40/Mt and a 20% before tax financial return) is 67.2 billion barrels.

The CO_2 demand associated with this economically recoverable oil is 19.9 billion metric tons. Approximately 2.3 billion metric tons of CO_2 demand for CO_2-EOR is expected to be provided from natural gas processing plants and natural sources of CO_2, providing a demand of 17.6 billion metric tons from CO_2 emissions captured by electric power and other industrial plants.

Figure II-4. Domestic Oil Supplies and CO_2 Demand (Storage) Volumes from "Next Generation" CO_2-EOR Technology**



*At an oil price of $85/B, a CO_2 market price of $40/mt and a 20% ROR, before tax.
**Includes 2,300 million metric tons of CO_2 provided from natural sources and 2.6 billion barrels already produced or being developed with miscible CO_2-EOR.
Source: Advanced Resources Int'l (2011).

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2. Oil Recovery and CO_2 Storage: Residual Oil Zone ("ROZ")

No discussion of "Next Generation" CO_2-EOR technology would be complete without at least a preliminary treatment of the major volumes of additional oil that exist in the residual oil zone (ROZ).

Our estimated oil recovery potential from using CO_2-EOR in the ROZ, below 56 large, existing Permian Basin oil fields, is 11.9 billion barrels of technically recoverable oil. This provides CO_2 storage capacity of 4.8 billion metric tons.[3] Additional technically recoverable ROZ oil resources, equal to 4.4 billion barrels and providing 1.7 billion metric tons of CO_2 storage capacity, exist underneath 13 oil fields in the Big Horn[4] and underneath 20 oil fields in the Williston[5] basins.

The scope of work for this study did not include providing an economically recoverable assessment of conducting CO_2-EOR in residual oil zones (ROZs).

C. *CO_2 Market Demand and CO_2 Storage from "Next Generation" CO_2-EOR Technology: Base Case Oil Price and CO_2 Costs*

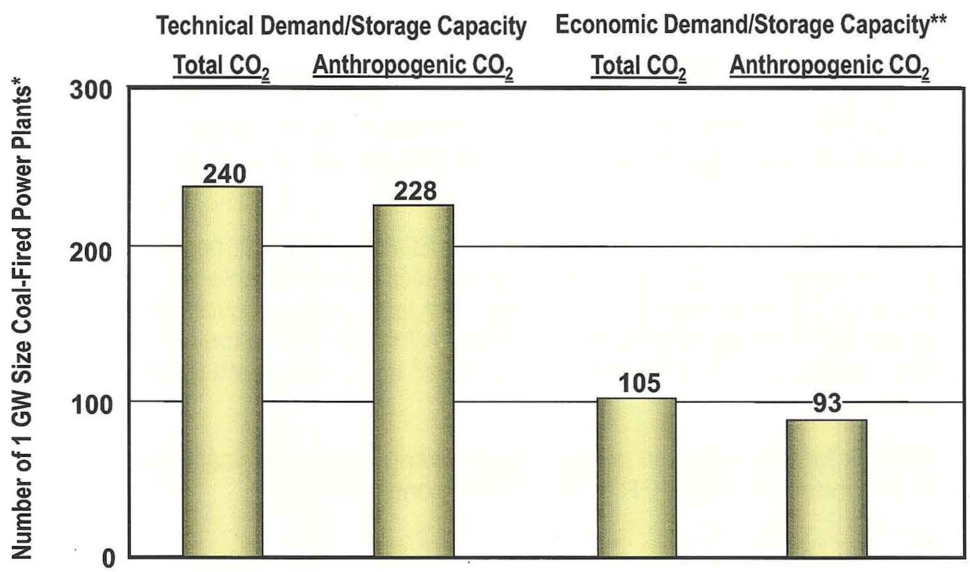
The technical CO_2 demand associated with "Next Generation" CO_2-EOR is 45.4 billion metric tons. The economic demand (and subsequent storage) for CO_2 with "Next Generation" CO_2-EOR is 19.9 billion metric tons, with about 2.3 billion metric tons of CO_2 provided by natural sources and existing natural gas processing plants.

However, large numbers such as billions of tons of CO_2 demand and storage capacity are different to grasp and thus often of limited value.

An alternative way to illustrate the CO_2 demand and storage capacity offered by "Next Generation" CO_2-EOR is to use the metric of the number of one-GW size power plants that could rely on CO_2-EOR for purchasing and storing their captured CO_2, Figure II-5:

- After subtracting out the 2.3 billion metric tons of CO_2 supply currently available, CO_2-EOR still offers sufficient technical storage capacity for all of the anthropogenic CO_2 captured from 228 one-GW size coal-fired power plants for 30 years of operation.
- Similarly, the volume of economic demand (and storage capacity) for anthropogenic CO_2 offered by CO_2-EOR, is substantial, equal to 93 one-GW size coal-fired power plants, after subtracting out the CO_2 supplies available from natural sources and natural gas processing plants.

Figure II-5. Volumes of Anthropogenic CO_2 Storage Capacity Available from "Next Generation" CO_2-EOR Technology



*Assuming 7 MMmt/yr of CO_2 emissions, 90% capture and 30 years of operations per 1 GW of generating capacity.
**At an oil price of $85/B, a CO_2 market price of $40/mt and a 20% ROR, before.
Source: Advanced Resources Int'l (2011).

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D. Impacts of Alternative Oil Prices and CO_2 Market Prices on CO_2-EOR Volumes and CO_2 Demand/Storage

The study undertook a series of sensitivity studies to gain insights on how alternative (higher and lower) oil prices and alternative (higher and lower) CO_2 market prices would impact results. Using historical ±30% bounds for future oil prices and historical ratios that relate CO_2 market prices to oil prices, the following nine cell price sensitivity matrix was constructed, Table II-2:

Table II-2. Oil and CO_2 Prices Used in Sensitivity Analysis

Oil Price	CO_2 Market Price (% of oil price, in $/Mcf)					
($/B)	Low: 2%		Base: 2.5%		High: 3%	
	($/Mcf)	($/Mt)	($/Mcf)	($/Mt)	($/Mcf)	($/Mt)
Low: $60	1.20	23	1.50	28	1.80	34
Base: $85	1.70	32	**2.12**	**40**	2.55	48
High: $110	2.20	42	2.75	52	3.30	62

The sensitivity study shows that the volumes of economic oil production and CO_2 demand (and storage) from "Next Generation" CO_2-EOR are highly sensitive to oil and CO_2 market prices, as shown on Tables II-3 and II-4 below:

Table II-3. Sensitivity Analysis of Oil Recovery (Billion Barrels): National Totals*

Oil Price	CO_2 Market Price (% oil price, $/Mcf)		
($/B)	Low: 2%	Base: 2.5%	High: 3%
Low: $60	60.4	59.1	**56.6**
Base: $85	69.1	**67.2**	65.8
High: $110	**73.5**	72.1	70.7

*Includes 2.6 billion barrels of oil already produced or placed in reserves with miscible CO_2-EOR.

Table II-4. Sensitivity Analysis of CO_2 Demand (Billion Metric Tons): National Totals*

Oil Price	CO_2 Market Price (% oil price, $/Mcf)		
($/B)	Low: 2%	Base: 2.5%	High: 3%
Low: $60	17.7	17.1	**16.0**
Base: $85	20.7	**19.9**	19.3
High: $110	**22.3**	21.7	21.0

*Includes 2,300 million metric tons of CO_2 from natural sources and natural gas processing plants.

- The high oil price ($110/B) and low CO_2 market price (2%) case adds about 6.3 billion barrels of oil recovery and 2.4 billion metric tons of CO_2 demand (and storage) compared to the Base Case (national totals).

	High Oil/Low CO_2	Base Case
Oil Recovery (B bbls)	73.5	67.2
CO_2 Demand/Storage (B mt)*	22.3	19.9

*Includes 2,300 million metric tons of CO_2 from natural sources and natural gas processing plants and 2.6 billion barrels of oil already produced or being developed with miscible CO_2-EOR.

- At a low oil price ($60/B) and high a CO_2 market price (3%), the "Next Generation" CO_2–EOR oil recovery is 10.5 billion barrels less and the CO_2 storage potential is 3.9 billion metric tons lower compared to the Base Case (national totals):

	Low Oil/High CO_2	Base Case
Oil Recovery (B bbls)	56.6	67.2
CO_2 Demand/Storage (B mt)*	16.0	19.9

*Includes 2,300 million metric tons of CO_2 from natural sources and natural gas processing plants and 2.6 billion barrels of oil already produced or being developed with miscible CO_2-EOR.

III. THE PERMIAN BASIN CO_2-EOR CASE STUDY

The purpose of the Permian Basin CO_2-EOR Case Study is to provide the reader basic information, historical context and benchmarks by which to independently assess the realism of the projections for current "State of Art" and tomorrow's "Next Generation" CO_2 enhanced oil recovery as set forth in this study and report. As such, this Chapter addresses the following three questions:

1. *What is the outlook for CO_2-EOR in the Permian Basin?*
2. *What does a successful CO_2-EOR project look like?*
3. *How closely do the results of this "Next Generation" CO_2-EOR study, match the key industry-used "benchmarks" for CO_2-EOR performance of: (a) oil recovery efficiency; (b) the net CO_2/oil ratio; and (c) costs and economic viability?*

A. *Outlook for CO_2 Enhanced Oil Recovery in the Permian Basin*

CO_2 enhanced oil recovery is underway in 56 Permian Basin oil fields, ranging from the field-wide CO_2 flood in the giant Wasson (San Andres) oil field to the small, 160 acre pilot CO_2 flood at Dollarhide (Clearfork). These 56 EOR projects produced about 200,000 barrels per day of incremental oil production during 2010, with five large CO_2-EOR projects accounting for the bulk of this production (Table III-1):

Table III-1. Oil Production from Major Permian Basin Fields Under CO_2-EOR (2010)

	Primary Operator	Total Field Production (B/D)	Incremental CO_2-EOR Production ** (B/D)
Wasson*	Occidental	51,100	44,600
Kelly Snider	KinderMorgan	29,600	26,500
Seminole	Hess	16,500	16,500
Slaughter**	Occidental	18,800	11,200
Means	ExxonMobil	10,000	8,700
Total		**126,000**	**107,500**

Source: Oil and Gas Journal, April 2010.
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*Combined production from six Wasson units.
**Combined production from nine Slaughter units.

It is notable that for these five giant oil fields, CO_2-EOR accounts for 85% of the total oil currently produced from the portions of the field under a CO_2-EOR flood. For example, without CO_2-EOR, the giant Wasson oil field, currently providing 51,100 barrels of oil per day, would only produce 6,500 barrels of oil per day.

Permian Basin oil production from CO_2-EOR has grown steadily for the past ten years. Recently, the rate of growth has been constrained by lack of CO_2 supplies. However, steps are underway that could, at least in part, help overcome the CO_2 supply constraint. For example:

- Kinder Morgan has recently expanded the CO_2 transportation capacity of its Cortez pipeline by 200 MMcfd and increased the production capacity of its SW Colorado natural CO_2 fields (Doe Canyon and McElmo Dome) by 300 MMcfd. It has plans to further increase its CO_2 production and Cortez pipeline capacity by an additional 200 MMcfd in 2011.

- OxyPermian is investing $850 million in the Century natural gas/CO_2 processing plant and associated pipeline facilities. Train I, with CO_2 capacity of 260 MMcfd, is due on line at the end of 2010. Train II, with CO_2 capacity of 180 MMcfd, is come on line in early 2012. The CO_2 will be used by Oxy to accelerate and enhance the development of its Permian Basin CO_2-EOR projects. This investment will capture 3.5 Tcf (180 million metric tons) of CO_2 for EOR and will enable Oxy to expand its Permian oil production by at least 50,000 barrels per day by 2015[9].

- Numerous planned advanced coal-based power plants equipped with CO_2 capture, such as Summit's Texas Clean Energy IGCC Project, are being located in West Texas, looking to sell their captured CO_2 to the CO2-EOR industry.

While still constrained by lack of sufficient volumes of CO_2, a number of new CO_2-EOR projects are being started or expanded:

- Kinder Morgan is planning a CO_2-EOR flood for the Katz (Strawn) oil field, looking to recover 24 million incremental barrels from the 150 million barrels of OOIP in-place in this field. By extending their SACROC CO_2 pipeline, Kinder Morgan is expecting to access an additional 100 million barrels of oil recovery from initiating CO_2 floods in the numerous other oil fields along the pipeline route to the Katz field area.

- OxyPermian has announced plans to initiate new CO_2-EOR floods at North Dollarhide (Clearfork) and SW Levelland Unit (San Andres) in 2010 and 2011.

- The most exciting news in the Permian Basin is the steady expansion of CO_2 floods in the residual oil zone (ROZ) below and beyond existing oil fields. Of particular interest are the commercial-scale (2,380 acre, 29 pattern Stage 1) ROZ flood underway by Hess at Seminole and the joint DOE/NETL and Legado ROZ field research pilot at Goldsmith.

[9] Investor presentation, October, 2010

B. A Successful CO_2-EOR Project in the Permian Basin

CO_2 injection into the Denver Unit of the giant Wasson (San Andres) oil field began in 1985, helping arrest the steep drop in oil production. Before the start of CO_2-EOR, oil production had declined from about 90,000 B/D to 40,000 B/D in 10 years. After the initiation of the CO_2 flood, oil production increased to about 50,000 B/D. Today, twenty four years after the start of the flood, the Denver Unit still produces at 30,000 B/D (Figure III-1).

At the completion of the CO_2 flood, Oxy expects the Denver Unit to recover nearly 67% of the approximately 2 billion barrels of original oil in-place, with CO_2-EOR providing 19.4% on top of an already high 47.3% recovery efficiency achieved in the Denver Unit from primary recovery and the waterflood (Table III-2).

To a significant degree, it appears that OxyPermian has been applying many of the initial features of "Next Generation" CO_2-EOR technology at the Denver Unit, including increasing the volumes of CO_2 injected, working to improve reservoir sweep efficiency, and conducting rigorous reservoir surveillance.

Figure III-1. CO_2-EOR Results at the Denver Unit of the Wasson Oil Field

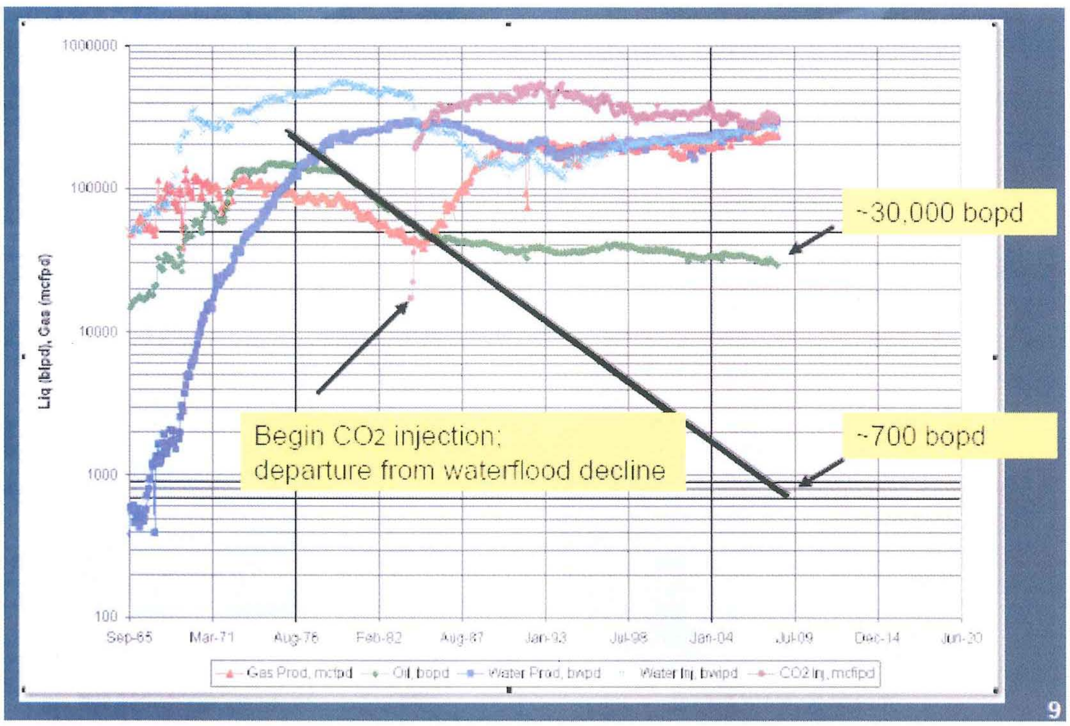
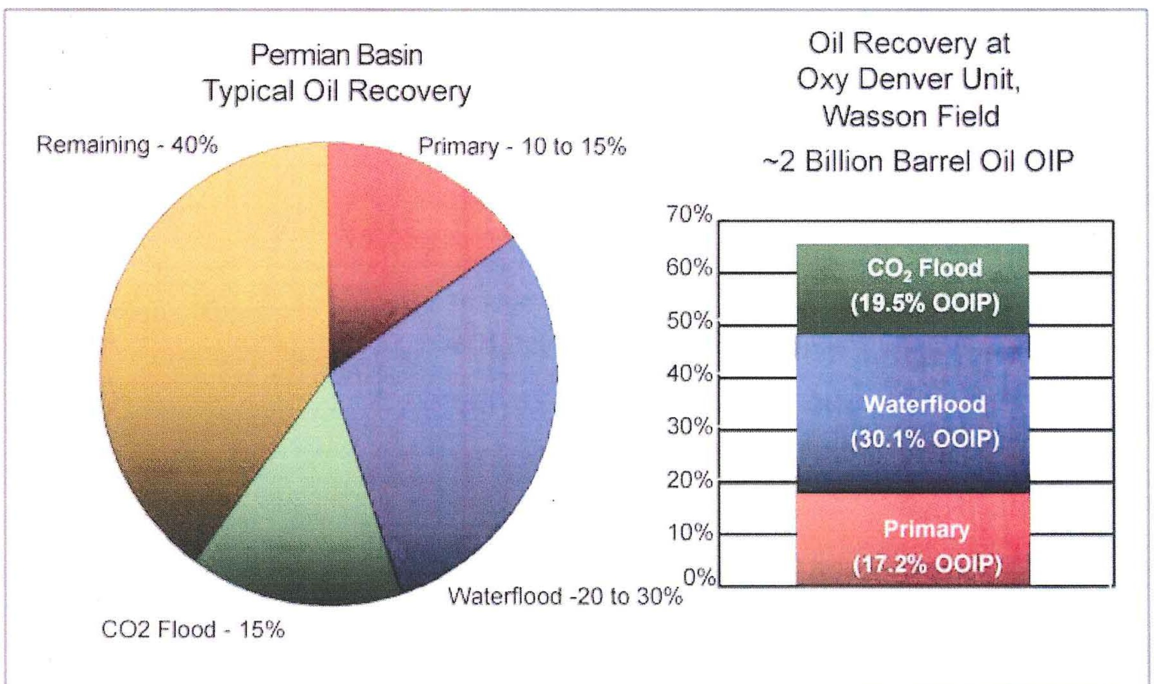


Table III-2. Oil Recovery Efficiency at the Denver Unit of the Wasson Oil Field

Recovery Method	Oil Recovery Efficiency (%OOIP)
• Primary	17.2%
• Waterflood	30.1%
• CO2 Flood	19.5%
Total Oil Recovery	**66.8%**

Figure III-2 compares the oil recovery performance of typical Permian San Andres Formation CO_2 floods with the CO_2 flood performance at the Denver Unit of the Wasson oil field, based on information from OxyPermian. As shown in Figure IV-2, the Wasson Denver Unit CO_2 flood has an expected oil recovery efficiency of 19.5% from the CO_2 flood, compared to an expected 15% recovery efficiency from a typical Permian Basin CO_2 flood. The extra 4.5% of recovery efficiency at the Wasson Denver Unit is equal to 90 million barrels of oil and an additional $7.6 billion dollars of revenue (at an oil price of $85 per barrel), demonstrating the value of pursuing advances in CO_2-EOR technology.

Figure III-2. Oil Recovery Performance From Permian Basin San Andres Formation



Modified from Oxy (2009)

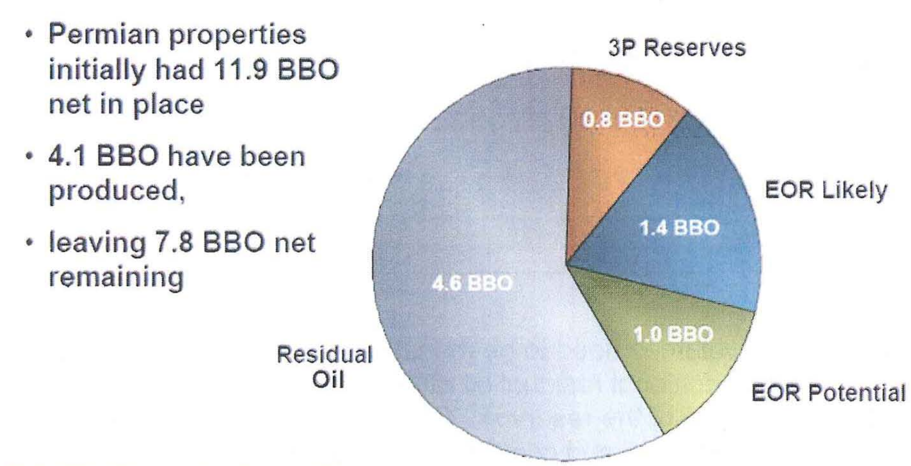
C. *Applying Industry Benchmarks*

1. OxyPermian's Expectations for Oil Recovery Efficiency

A most useful outlook on expected CO_2-EOR recovery efficiency is provided in the recent analyst presentations by Occidental Petroleum for its Permian Basin EOR opportunities.[10] For perspective, Occidental is the largest onshore/Lower 48 oil producer and also the largest operator of CO_2-EOR projects in the Permian Basin.

- Oxy's Permian oil properties have 11.9 billion barrels (net) of original oil in-place. Of this, 4.1 billion barrels (net) have been produced, with an estimated 0.6 billion barrels of this from past application of CO_2-EOR at Oxy's large oil fields such as Wasson (Denver Unit) (Figure III-3).

Figure III-3. Occidental Petroleum's Permian Basin EOR Opportunities



Source: Occidental Petroleum Corporation, May 2010

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- Of the 7.8 billion barrels (net) remaining, Oxy expects to recover 2.4 billion barrels from applying CO_2 enhanced oil recovery, with 1.4 billion barrels as likely and 1.0 billion barrels as potential (Figure III-3).

- Overall, Oxy has expectations for recovering 3 billion of the 11.9 billion barrels of original oil in-place (net) from applying CO_2-EOR in the Permian Basin. This is equal to an ultimate recovery efficiency for CO_2-EOR of over 25% of OOIP. Oxy's expectations for CO_2-EOR performance in the Permian Basin are consistent with the oil recovery efficiencies from "Next Generation" CO_2-EOR technology determined by this study.

[10] Investor presentation, October, 2010.

2. CO_2 "Slug Size" and the Net CO_2/Oil Ratio

In the past, operators used small-volume injections of CO_2 (0.4 to 0.5 hydrocarbon pore volume (HCPV)) to maximize profitability. With higher oil prices, CO_2-EOR economics favor using considerably higher volumes of CO_2. The evolution toward using higher volumes of CO_2 is illustrated by Oxy's experience at the Eastern Denver Unit of the Wasson oil field (Figure III-4).

Figure III-4. Evolution of "Industry Standard" for Volume of CO_2 Injection ("Slug Size")

Eastern Denver Unit (Wasson Oil Field) CO_2-EOR Project	Started
Start of CO_2 injection in EDU with 40% HCPV CO_2 slug size	1984
EDU WAG & start off CO_2 injection in WAC, FIA, B8 FIA	1989
Non performing FIA patterns stopped (~20% HCPV CO_2 slug size)	1992
EDU 40% to 60% HCPV CO_2 slug size increase approved	1994
EDU 60% to 80% HCPV CO_2 slug size increase approved	1996
EDU 80% to 100% HCPV CO_2 slug size increase approved	2001

Source: OXY Permian 2006

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These increased CO_2 volumes need to be managed and controlled to assure that the injected CO_2 contacts additional residual oil rather than merely re-circulates through already contacted portions of the reservoir. One of the purposes of "Next Generation" reservoir feedback, diagnostics and control ("surveillance") is to better manage the productive use of injected CO_2.

Based on using larger volumes of CO_2 injection and reservoir surveillance, OxyPermian anticipates a net CO_2 requirement of 5 Tcf for producing its next billion barrels of oil with CO_2-EOR from the Permian Basin (Table III-3).

Table III-3. Permian Reserves and CO_2 Requirements – "The Next Billion Barrels"

	Net 3P Reserves (MMBOE)	Net CO_2 Required (Tcf)
• Developed	570	2.8
• Undeveloped	430	2.2
Total	1,000	5.0

Source: OxyPermian

OxyPermian's expectations of a net 5 Mcf/BO as their future CO_2/oil ratio for their Permian Basin oil properties is consistent with our projected CO_2/oil ratio performance for "Next Generation" CO_2-EOR in the Permian Basin.

Of additional interest is a supporting set of analyses on the relationship of volumes of CO_2 injection and enhanced oil recovery as provided by Marchant (2010) in the SPE paper "Life Beyond 80 – A Look at Conventional WAG Recovery Beyond 80% HCPV Injection in CO_2 Tertiary Floods."[11] His statement -- "Tertiary oil recovery under CO_2 injection is a function of the total amount of CO_2 injected" -- is supported by the following analysis in his paper, summarized on Table III-4.

Table III-4. Relationship of Oil Recovery to CO_2 Injection Volumes

Size of CO_2 Slug	Oil Recovery from CO_2-EOR
(HCPV)	(% OOIP)
50%	15%
100%	21%
190%	26%

3. Costs and Economic Viability

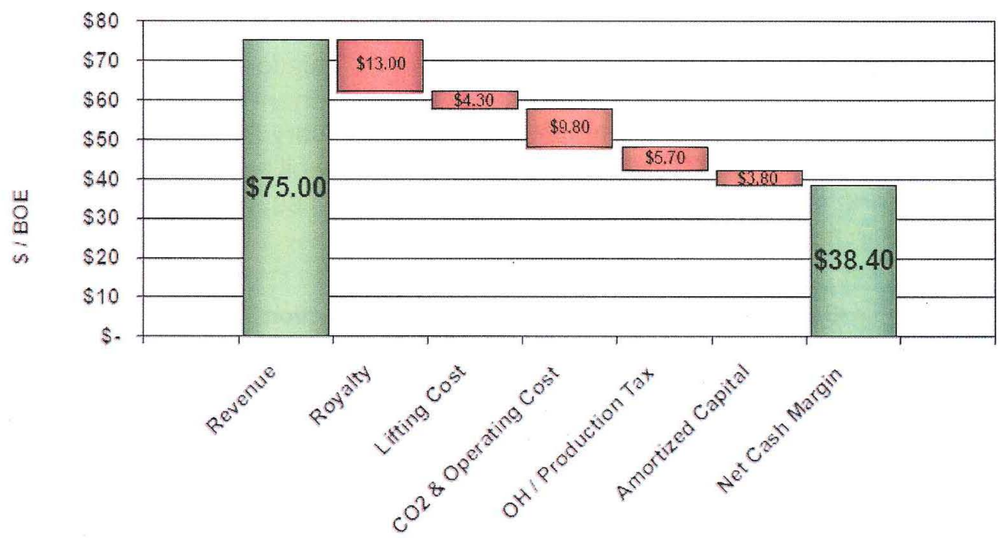
With recent higher oil prices, currently ranging from \$75 to over \$100 per barrel, and the rigorous pursuit of cost-efficiencies, the economics of CO_2-EOR have improved markedly.

Based on publicly presented information and using an oil price of \$75 per barrel, Occidental Petroleum expects its Permian Basin CO_2-EOR projects to provide a net cash margin of over \$38 per barrel, after subtraction of royalties, operating costs, CO_2 purchase and amortized capital (Figure III-5). At \$100 per barrel and including more current information on costs, Occidental Petroleum expects a net cash margin of about \$56 per barrel (Figure III-6).

Even with the costs of conducting pilot floods and the delay between investment of capital and the production of oil typical of a CO_2-EOR project, this cost analysis indicates that the CO_2-EOR projects in the Permian Basin can provide very favorable economics.

[11] Merchant, D.H., "Life Beyond 80 – A Look at Conventional WAG Recovery Beyond 80% HCPV Injection in CO_2 Tertiary Floods", SPE 139516, for presentation at the SPE International Conference on CO_2 Capture, Storage and Utilization, New Orleans, LA, 10-12 November 2010.

Figure III-5. Typical Permian Basin CO_2-EOR Project Cost Structure (Occidental Petroleum)



*$75/Bbl Marker Price
Source: Occidental Petroleum Corporation, May 2010

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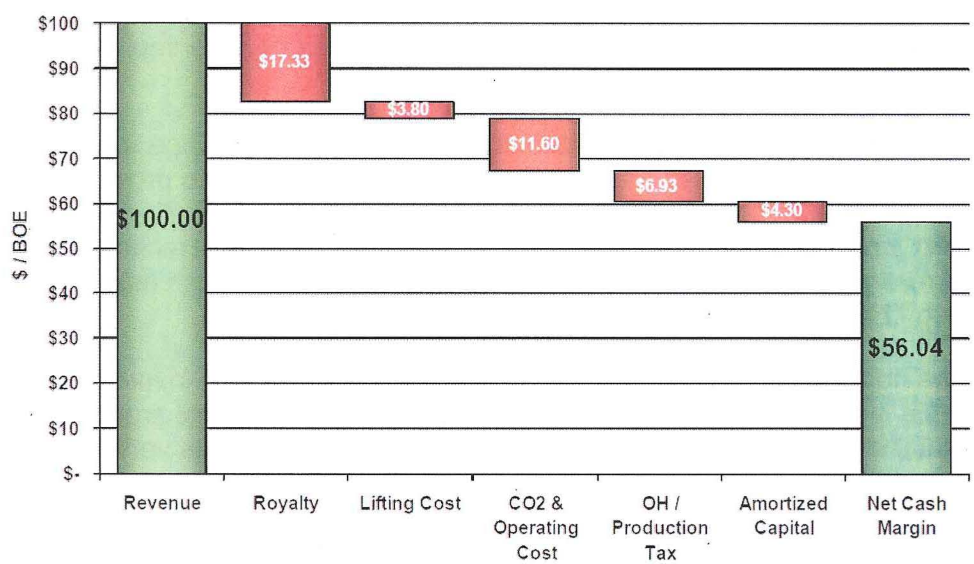
Figure III-6. Updated Typical Permian Basin CO_2-EOR Project Cost Structure (Occidental Petroleum)



*$100/Bbl Marker Price
Source: Occidental Petroleum Corporation, May 2011

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IV. "NEXT GENERATION" CO_2-EOR TECHNOLOGIES

As set forth in the Executive Summary, "Next Generation" CO_2-EOR consists of four realistically achievable advanced technologies:

1. Improvements in currently practiced CO_2-EOR technology,
2. Advanced near miscible CO_2-EOR technology,
3. Application of CO_2-EOR to residual oil zones (ROZs), and
4. Deployment of CO_2-EOR in offshore oil fields.

Each of these "Next Generation" CO_2-EOR technologies is further discussed in the sections below.

A. Improvements in Currently Practiced CO_2-EOR Technology.

The improved version of CO_2-EOR technology envisioned under "Next Generation" would address five of the opportunities for improving the performance of currently practiced State of Art (SOA) CO_2-EOR technology, namely:

- Increasing the volume of CO_2 injected,
- Capturing more of the remaining mobile and immobile oil,
- Improving sweep efficiency and mobility control (reservoir conformance),
- Improving the technology of reservoir surveillance, and
- Lowering the threshold minimum miscibility pressure (MMP).

To examine the impact on oil recovery and CO_2 storage of these improvements to currently practiced CO_2-EOR technology, we selected an "example" San Andres oil reservoir in the Permian Basin, with reservoir properties and past oil recovery performance shown in Table IV-1.

Table IV-1. Example Permian Basin San Andres Formation Oil Reservoir

Reservoir Properties		Oil Resource and Recovery Data	
Depth	4,200 ft	Original Oil In-Place	930 MMBbls
Net Pay	220 ft	Ultimate P/S Rec.	325 MMBls
Porosity	9.40%	Recovery Efficiency	35%
Initial Oil Saturation	0.77	Swept Zone Sor	0.32
Initial FVF	1.17	Current FVF	1.07
Initial Pressure	1,800 psi	P/S Sweep Efficiency	64%
Temperature	99° F	"Unswept" Zone Sor	0.59
Oil Gravity	35° API	Min. Miscibility Pressure	1,300 psi
Oil Viscosity	3.5 cp	Dykstra-Parsons	0.78

The "example" oil reservoir is large, with 930 million barrels of original oil in-place (OOIP). The reservoir is near-depleted, with over 90% of its 325 million barrels of ultimate primary/secondary recovery already produced. The oil recovery efficiency for this "example" San Andres Formation light oil (35° API) reservoir is 35% of OOIP. However, this still leaves a most attractive "stranded" oil target of over 600 million barrels still in-place.

Even with an oil viscosity of 3.5 cp and a Dykstra-Parsons heterogeneity co-efficient of 0.78, the waterflood sweep efficiency of this "example" oil reservoir is good at 64%. While the oil saturation in the swept zone of the reservoir has been reduced to 32%, additional mobile oil remains in its poorly swept zones.

With significant "stranded" (residual) oil and a minimum miscibility pressure of 1,300 psi, compared to an initial reservoir pressure of 1,800 psi, this "example" San Andres oil reservoir is an attractive candidate for miscible CO_2 enhanced oil recovery.

1. Applying State of Art (SOA) CO_2-EOR

As the starting point for the analysis, we modeled the "example" San Andres oil reservoir using *PROPHET2* under "State of Art" (SOA) CO_2-EOR technology.

In the "State of Art" case, using 1 HCPV of CO_2 injection and a tapered WAG, the anticipated technical oil recovery for this "example" oil reservoir is 148 million barrels, produced from 174, forty acre inverted 5-spot patterns.

- Overall technical oil recovery efficiency in the SOA case is 15.9% of OOIP, representative of a geologically favorable San Andres oil reservoir developed with current CO_2-EOR practices.
- The net (purchased) CO_2 to oil ratio is 7.6 Mcf of CO_2 per barrel of technically recovered oil (Mcf/BO), with a gross CO_2 to oil ratio of 15.7 Mcf/BO. This is reasonably representative of a somewhat higher viscosity (3.5 cp) and moderately heterogeneous (DP = 0.78) San Andres oil reservoir under a CO_2 flood.
- It is useful to note that in the SOA case, this "example" San Andres oil reservoir just barely achieves its minimum rate of return (ROR) hurdle rate of 20%, before tax, at an oil price of $85 per barrel and a CO_2 market price of $40 per metric ton ($2.11 per Mcf of CO_2). The reason is that the investment payback period is long, at 7 years.
- In addition, because ARI's economic model features an economic truncation feature that stops a project once annual costs exceed annual revenues, approximately 6 million barrels of the technically recoverable oil remains unproduced. This economic truncation reduces economic (actual) oil recovery efficiency to 15.3% and increasing the net CO_2/oil ratio to 7.9 Mcf/BO.

In the sections below, we will examine the impact on technical and economic oil recovery and CO_2 demand (storage) of applying the various "Next Generation" CO_2-EOR technologies, to this "example" oil reservoir first individually and then in combination.

2. Assessing Impacts of "Next Generation" CO_2-EOR Technology

Each of the "Next Generation" technologies has been formulated to address one or more of the major problems impeding the more efficient performance of today's "State of Art" (SOA) CO_2-EOR technology.

- The first problem is less than optimum reservoir contact by CO_2 due to inadequate volumes of injected CO_2. "Next Generation" technology involves injecting greater quantities of CO_2, up to 1.5 HCPV.

- The second problem is poor reservoir sweep efficiency due to a high fluid mobility ratio, particularly in cases when the viscosity of the CO_2 and water is considerably less than the viscosity of the reservoir oil. "Next Generation" technology involves improving the mobility ratio by increasing the viscosity of the displacing water in the WAG process to 2 cp.

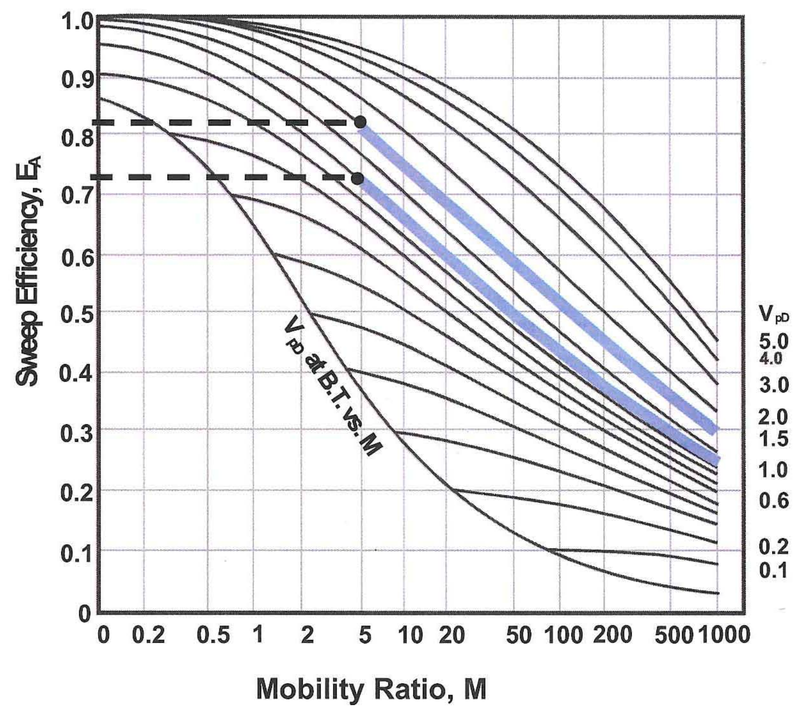
- The third problem is inefficient reservoir contact and low sweep efficiency (poor reservoir conformance) due to high geologic complexity and reservoir heterogeneity. "Next Generation" technology involves improving reservoir contact by drilling an additional CO_2 injection well to target the mobile oil "stranded" in the reservoir.

Supporting the application of each of the three specific "Next Generation" technologies is the use of rigorous reservoir surveillance (reservoir feedback, diagnostics and control). Without rigorous reservoir surveillance, the benefits of applying these three "Next Generation" CO_2-EOR technologies would be much less.

(a). Increasing the Volume of CO_2 Injected. The first "Next Generation" technology option involves the increasing CO_2 injection volumes to 1.5 HCPV. Higher HCPVs of injected CO_2 enable more of the reservoir's residual oil to be contacted by the injected CO_2. However, higher volumes of CO_2 injection can also lead to longer overall project length and higher gross CO_2 to oil ratios. Because oil reservoirs with already high sweep efficiency may not gain sufficient benefits in relation to costs, the economic truncation algorithm within ARI's CO_2-EOR economic model limits the volume of CO_2 that is injected. This truncation algorithm works as a function of oil price and CO_2 costs.

Reservoir engineering theory and analyses argue that increasing the volume of CO_2 injected (V_{pD}), from 1.0 HCPV to 1.5 HCPV, should improve the areal sweep efficiency (E_A) from about 73% to about 82% for a 4.4 mobility ratio (M) situation, as shown by the type curves prepared by Claridge (1972) (Figure IV-1). This is equal to an increase in areal sweep efficiency of about 12%.

Figure IV-1. Areal Sweep Efficiency in Miscible CO_2 Flooding as a Function of HCPV CO_2



Note: V_{pD} is hydrocarbon pore volumes of injected CO_2.

Source: Claridge, E.L., "Prediction of Recovery in Unstable Miscible Displacement", (J)SPE 12(2) 143-155 (April 1972).

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By increasing the volume of CO_2 injected from 1.0 HCPV to 1.5 HCPV, the *PROPHET2* model shows an increase in oil recovery efficiency of 20 million barrels for the "example" oil reservoir. This provides an increase of about 14% (168 MMB/148 MMB) in oil recovery over the SOA (1.0 HCPV) case. Technical oil recovery efficiency increases from 15.9% of OOIP with 1 HCPV of CO_2 injection to 18.1% of OOIP with 1.5 HCPV of CO_2 injection, Table IV-2. Advanced reservoir surveillance is essential to ensure that the increased volumes of injected CO_2 contact more of the reservoir and does not merely circulate through already swept reservoir intervals.

Interestingly, the economic benefits of injecting a higher HCPV of CO_2 are realized only with an ability to increase the CO_2 injection rate, enabling the 1.5 HCPV of CO_2 injection to be performed over the same time period as injecting the 1.0 HCPV of CO_2. With 1.5 HCPV of CO_2 and a 50% higher CO_2 injection rate, the project achieves a 29.2% ROR compared to 21.5% ROR in the SOA (1.0 HCPV, regular rate) case.

Table IV-2. Oil Recovery and Economic Impact of Increasing the Volume of CO_2 Injected

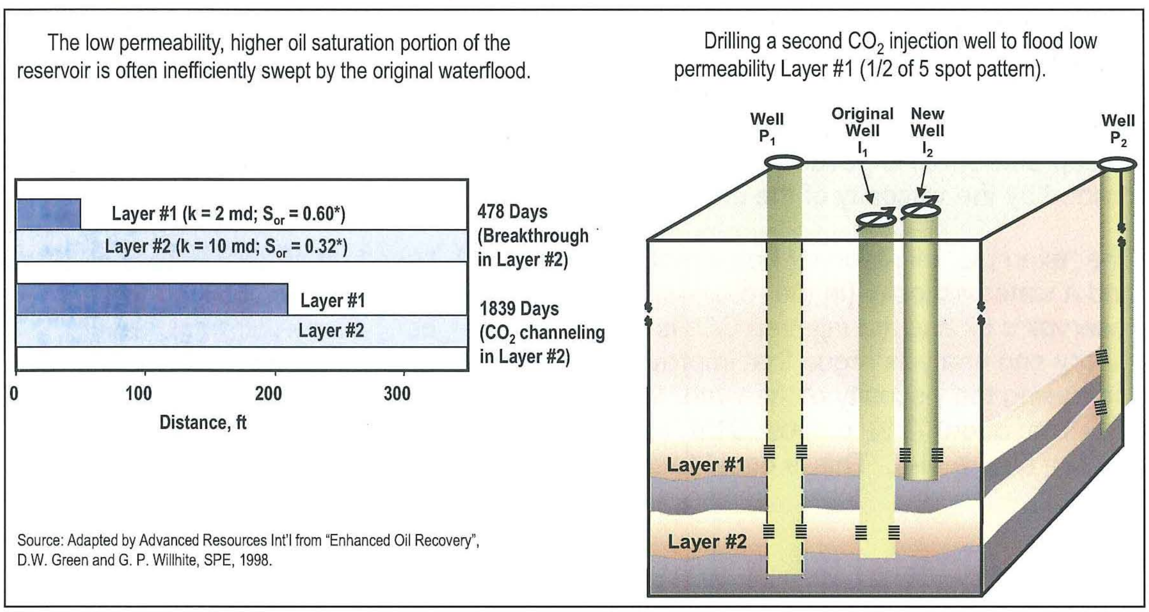
CO_2 Injection Volumes	Technical Oil Recovery		Project ROR
(HCPV/Injection Rate)	(MMBbls)	(% OOIP)	(Before Tax)
1.00/Regular Rate	148	15.9	21.5%
1.5/Regular Rate	168	18.1	20.6%
1.5/Higher Rate	168	18.1	29.2%

(b). Capturing More of the Remaining Mobile and Immobile Oil. It may be possible with optimized well design and placement to contact more of the remaining mobile oil (as well as more efficiently contact the swept zone residual oil) in a reservoir than continuing to use the existing waterflood pattern and well placement design.

The options for installing a modified CO_2 flood and well placement design include: (1) isolating the previously poorly-swept reservoir intervals (with higher residual oil) for targeted CO_2 injection; (2) drilling horizontal injection wells to target lower permeability reservoir intervals; (3) modifying the well pattern alignment; (4) using physical (or chemical) means for diverting CO_2 into previously poorly-contacted portions of the reservoir; and (5) drilling the reservoir at closer well spacing.

For the "example" oil reservoir in the "Next Generation" case, we added one new vertical CO_2 injection well to each pattern to target the previously poorly contacted portions of the reservoir, as shown in Figure IV-2.

Figure IV-2. Using Modified Pattern and Well Placement Design to Capture Mobil Oil



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To properly model the addition of a second injection well in each pattern, the reservoir is split into "fully swept" and "partially swept" zones. Adding a CO_2 injection well and modifying the flow pattern of the reservoir to contact the mobile oil left after the waterflood improves oil recovery by 5.1 % for the "example" oil reservoir. This improves technical oil recovery efficiency to 21% in the "modified pattern and well placement" case versus 15.9% in the SOA case. Adding a second CO_2 injection well also enables the project to increase CO_2 injectivity in a pattern area by 50%. Advanced reservoir surveillance is a key enabling technology for implementing changes in patterns and well placement designs for targeting left behind mobile oil.

While the drilling of the new CO_2 injection well adds $1.2 million of CAPEX per pattern for the "example" oil reservoir and increase O&M costs, the overall economics are significantly improved. The recovery of the additional 47 million barrels of oil and its earlier production (in the "modified pattern and well placement" case), increases the ROR to 77%, Table IV-3.

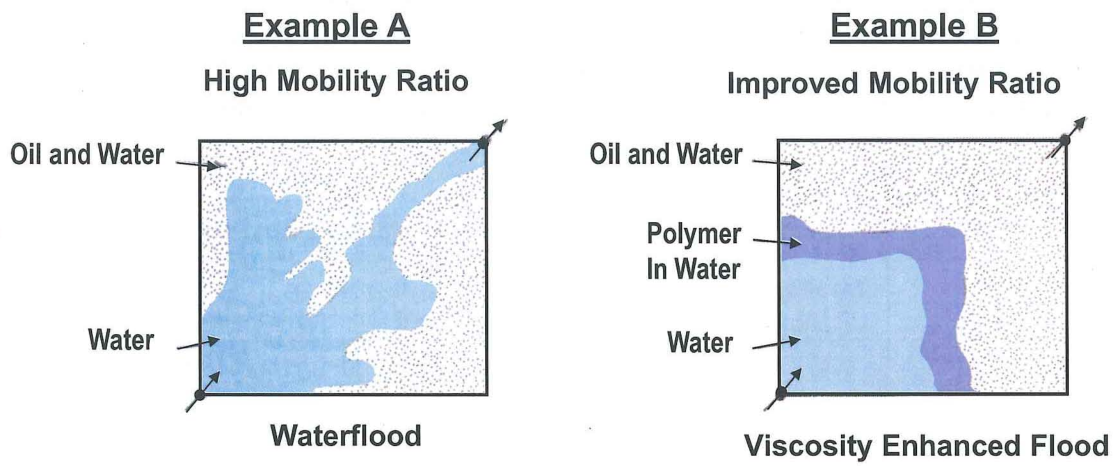
Table IV-3. Oil Recovery and Economic Impact of Modified Pattern and Well Placement

Pattern/Well Design	Technical Oil Recovery		Project ROR
	(MMBbls)	(% OOIP)	(Before Tax)
Existing Design (SOA)	148	15.9	21.5%
Modified Design ("Next Generation")	195	21.0	77.2%

(c). Improving Sweep Efficiency and Mobility Control (Reservoir Conformance). Often the viscosities of the injected fluids (CO_2 and water) are considerably lower than the viscosity of the reservoir oil, leading to viscous fingering of the CO_2 through the reservoir's oil and thus inefficient macroscopic displacement (sweep efficiency) in the reservoir, Figure IV-3. The extent of viscous fingering (and sweep efficiency) is governed by the mobility ratio -- the viscosity of the reservoir oil divided by the viscosity of the displacing fluids.

The "example" oil reservoir has a mobility ratio of 4.4, based on an oil viscosity of 3.5 cp and a water viscosity (in the reservoir) of 0.8 cp. (The mobility ratio between the reservoir's oil and the injected CO_2 is considerably higher.) Reservoir engineering theory and analysis argue that improving the oil/water mobility ratio from 4.4 to 1.7 (by increasing the viscosity of the water to 2 cp) should improve the areal sweep efficiency (E_A) from about 73% to about 81%, as shown by the type curves prepared by Claridge (1972), Figure III-4. This is equal to an increase in the areal sweep efficiency of about 11%.

Figure IV-3. Example of Viscous Fingering of CO_2 Due to Unfavorable Mobility Ratio*



*The mobility ratio is the viscosity of the reservoir oil divided by the viscosity of the displacing fluid.

Source: Adapted by Advanced Resources Int'l from "Enhanced Oil Recovery", D.W. Green and G. P. Willhite, SPE, 1998.

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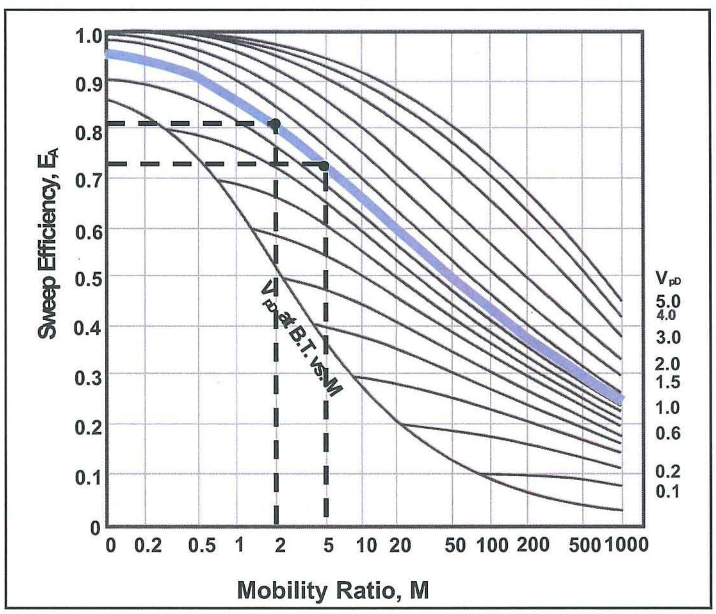
Figure IV-4. Areal Sweep Efficiency in Miscible CO_2 Flooding as a Function of Mobility Ratio

(Five-Spot Well Pattern)



Note: V_{pD} is displaceable fluid pore volumes of CO_2 injected.

Source: Claridge, E.L., "Prediction of Recovery in Unstable Miscible Displacement", (J)SPE 12(2) 143-155 (April 1972).

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After adding a polymer or other viscosity increasing agents to the drive water in the WAG CO_2 flood to change the mobility ratio from 4.4 to 1.7, the *PROPHET2* model shows an increase in the oil recovery of 10 million barrels for the "example" oil reservoir. Technical oil recovery efficiency increases to 17.0% with a 2 cp water WAG compared to 15.9% recovery efficiency with an 0.8 cp water in the WAG, Table IV-4. Again, rigorous reservoir surveillance is important for capturing the full benefits of improving sweep efficiency (reservoir conformance) with improved mobility control.

Table IV-4. Oil Recovery and Economic Impact of Improving the Mobility Ratio

Water Viscosity	Mobility Ratio	Technical Oil Recovery		Project ROR
(cp)	(M)	(MMBbls)	(% OOIP)	(Before Tax)
0.8	4.4	148	15.9	21.5%
2	1.7	158	17.0	27.0%

Importantly, improving the mobility ratio helps improve early time oil production, reducing the investment payback period to 5 years in the "Next Generation" case from 7 years in the SOA case and achieve a higher rate of return. (at a $85 per barrel of oil price and a $40 per metric ton of CO_2 cost), Table IV-4.

(d). Assessing Impact of the Combined Application of "Next Generation" Technologies. Not surprisingly, the integrated application of all three of the "Next Generation" technologies, combined with a rigorous program of reservoir feedback, diagnostics and control ("reservoir surveillance"), provides the largest impact:

- Economically feasible oil recovery increases to 244 million barrels (26.2% of OOIP) in the "Next Generation" case from 142 million barrels (15.3% of OOIP) in the SOA case.

- Even though the volume of purchased CO_2 is 50% larger, the net CO_2/oil ratio (due to higher oil recovery and improved control of the injected CO_2) is lower at 5.7 Mcf per barrel of oil in the "Next Generation" case versus 7.9 Mcf per barrel of oil in the SOA case.

- While overall CAPEX for the "Next Generation" CO_2 flood is higher (due to drilling more wells and increasing the size of the CO_2 recycle equipment) and the overall OPEX is higher (due to the costs of adding polymers to the injected water and conducting reservoir surveillance), the economics are significantly better. As shown in Table IV-5, the "Next Generation" CO_2-EOR project achieves a rate of return (ROR) of nearly 94% compared to 21.5% in the SOA case.

Table IV-5. Impact of Integrated Application of "Next Generation" CO_2-EOR Technology

Technology Case	Economic Oil Recovery		Net CO_2/Oil Ratio	Project ROR
	(MMBBbls)	(% OOIP)	(Mcf/BO)	(Before Tax)
State of Art	142	15.3	7.9	21.5%
"Next Generation"	244	26.2	5.7	93.8%

A particularly important finding emerges from the assessment of individual versus integrated application of "Next Generation" CO_2-EOR technology in the "example" oil reservoir:

- The sum of the individual (technology by technology) applications of "Next Generation" CO_2-EOR technology is 77 million barrels of increased oil recovery.
- The integrated application of the three "Next Generation" CO_2-EOR technologies provide 102 million barrels of increased oil recovery, about a third more than the sum from applying these technologies individually. Integrated application of "Next Generation" CO_2-EOR captures the beneficial synergistic interactions of these three improved technologies and provides a "sum that is greater than the parts."

(e). Lowering the Threshold Minimum Miscibility Pressure (MMP). A significant number of oil reservoirs, particularly in Appalachia, the Mid-Continent and the Illinois Basin, have reservoir pressures somewhat below MMP, relegating these oil reservoirs to use of less efficient near miscible or even immiscible CO_2-EOR technology. "Next Generation" CO_2-EOR technology, through use of miscibility enhancing additives, has a goal of reducing the MMP of oil reservoirs by 250 psi, enabling a larger number of oil reservoirs to be processed with miscible and near miscible CO_2-EOR. (The "example" oil reservoir was already favorable for miscible CO_2-EOR and thus would not benefit from this specific "Next Generation" technology.)

B. Advanced Near Miscible CO_2 Enhanced Oil Recovery Technology

1. Background

As discussed previously, a large number of oil reservoirs, particularly in Appalachia, the Illinois Basin and the Mid-Continent, have depths and oil properties unsuitable for achieving miscible CO_2 and its efficient oil displacement. However, recent laboratory and analytical work indicate that if the achievable reservoir pressure is close to minimum miscibility pressure (MMP), the oil reservoir can achieve reasonable oil recovery using near miscible CO_2-EOR technology.

While the exact parameters of the pressure range for near miscible CO_2-EOR have yet to be defined, we have established for this study a near miscibility reservoir pressure range of 75% to 99% of MMP. Reservoirs with achievable pressures of less than 75% of MMP would be assigned to immiscible CO_2 flooding, the analysis of which is beyond the scope of work of this study.

2. Resource Target

Various investigators have identified attractive targets for applying near miscible CO_2-EOR technologies to domestic oil fields. For example:

- The Illinois Geological Survey identified a large number of oil fields holding 3.8 billion barrels of OOIP in the Illinois Basin that would be attractive for near miscible CO_2-EOR technology. These reservoirs could provide 0.3 billion barrels of oil recovery and about 100 million metric tons of CO_2 storage capacity.[12]

- Work by the Chemical and Petroleum Engineering Department of the University of Kansas identified the Arbuckle Formation in Kansas as a large target for near miscible CO_2-EOR. To date, the Arbuckle Formation in Kansas has produced 2.2 billion barrels from about 8 billion barrels of OOIP. Most of the Arbuckle oil fields are close to abandonment, with 90% of the wells producing less than 5 barrels of oil per day. The Kansas study noted that near miscible CO_2-EOR offered the potential for recovery of up to 1 billion barrels from these Arbuckle Formation reservoirs.[13]

3. Mechanisms of Near Miscible CO_2-EOR

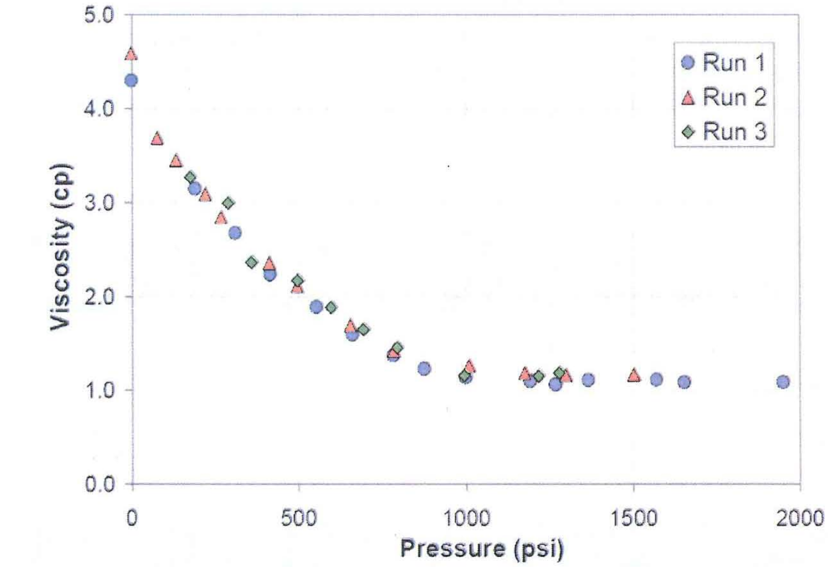
Three oil displacement mechanisms are important for near miscible CO_2-EOR:

- First, the injection of CO_2 and its dissolution into the oil phase, reduces the viscosity of the oil/CO_2 mixture providing a more favorable mobility ratio and thus improved sweep efficiency. Figure IV-5 shows the sharp reduction in oil viscosity, achieved by injecting CO_2 at 1,100 psig, from an initial 4.5 cp to about 1 cp, based on work by Kansas, for a 33° API oil at 110°F.

- Second, the dissolution of CO_2 into the oil phase causes the oil to swell, with the volume above residual oil saturation becoming mobile and displaceable with CO_2 and water. Figure IV-6 shows the increase (swelling) of the oil volume by about 30% due to dissolution of 0.7 mole fraction of CO_2 into the oil phase, in the near miscible region of 1,150 psig, as reported by the Kansas study,[13] for a 33° API oil at 110°F.

[12] Frailey, S.M., "CO_2 Flood Pilots in the Illinois Basin", PTTC IOR/EOR Illinois Basin Workshop, CO_2 Enhanced Oil Recovery, Illinois Basin Pilot Projects, Midwest Geological Sequestration Consortium, March 2, 2011, Evansville, IN.
[13] Bui, L.H., Tsau, J.S., and G.P. Willhite, "Laboratory Investigations of CO_2 Near-Miscible Application in Arbuckle Reservoir", SPE 129710, paper prepared and presented at the 2010 SPE Improved Oil Recovery Symposium, Tulsa, OK 24-28 April, 2010.

Figure IV-5. Effect of CO_2 Dissolution in Crude Oil on Viscosity.



Source: Bui, L.H., Tsau, J.S., and G.P. Willhite, "Laboratory Investigations of CO2 Near-Miscible Application in Arbuckle Reservoir", SPE 129710, paper prepared and presented at the 2010 SPE Improved Oil Recovery Symposium, Tulsa, OK 24-28 April, 2010.

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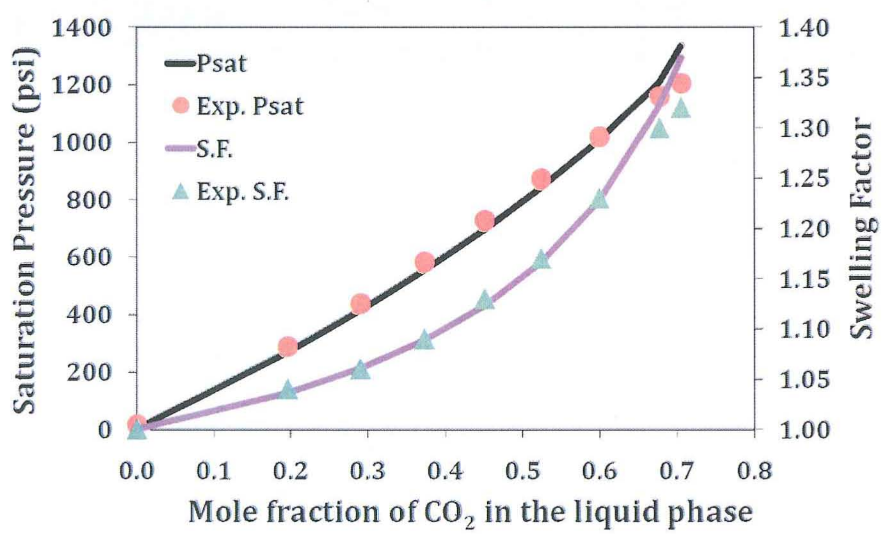
Figure IV-6. Saturation Pressure/Swelling Factor for Near Miscible CO_2-EOR



Source: Bui, L.H., Tsau, J.S., and G.P. Willhite, "Laboratory Investigations of CO2 Near-Miscible Application in Arbuckle Reservoir", SPE 129710, paper prepared and presented at the 2010 SPE Improved Oil Recovery Symposium, Tulsa, OK 24-28 April, 2010.

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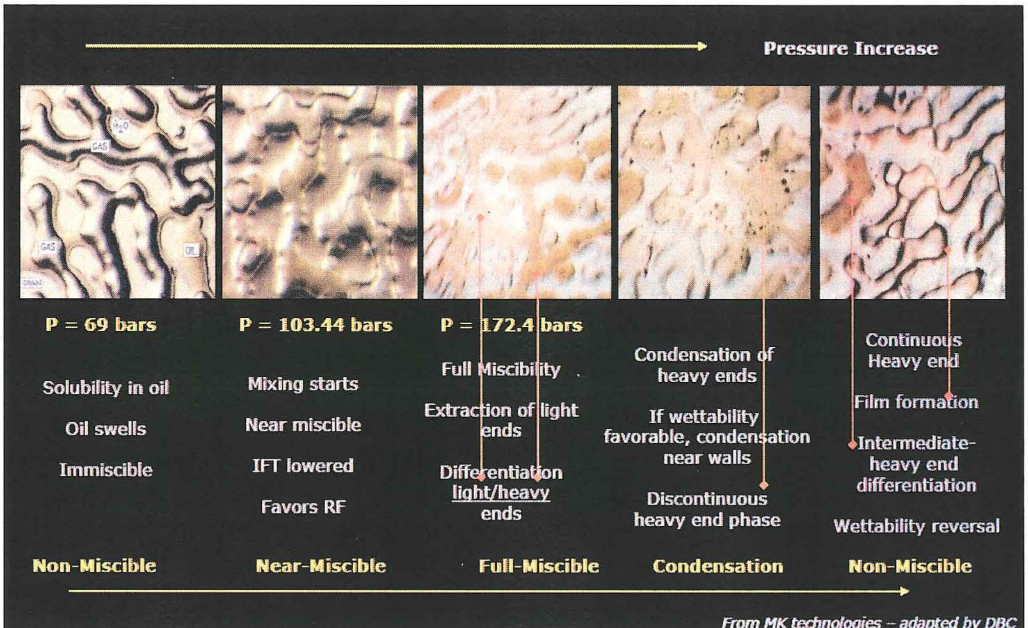
- Third, as reservoir pressure enters the near miscible pressure response range, the extraction and vaporization of light hydrocarbon components from the crude oil into the CO_2 vapor phase begins, the mixing of the CO_2 and oil phases progresses, and the interfacial tension (IFT) of the system is lowered, promoting improved oil recovery. Figure IV-7 shows that the onset of this mixing and lower IFT begins at about 60% of minimum miscibility pressure for the oil composition examined by IFP.[14]

Figure IV-7. Mechanisms of Near Miscible CO_2-EOR



Source: Bossie-Codreanu, IFP – March 2009

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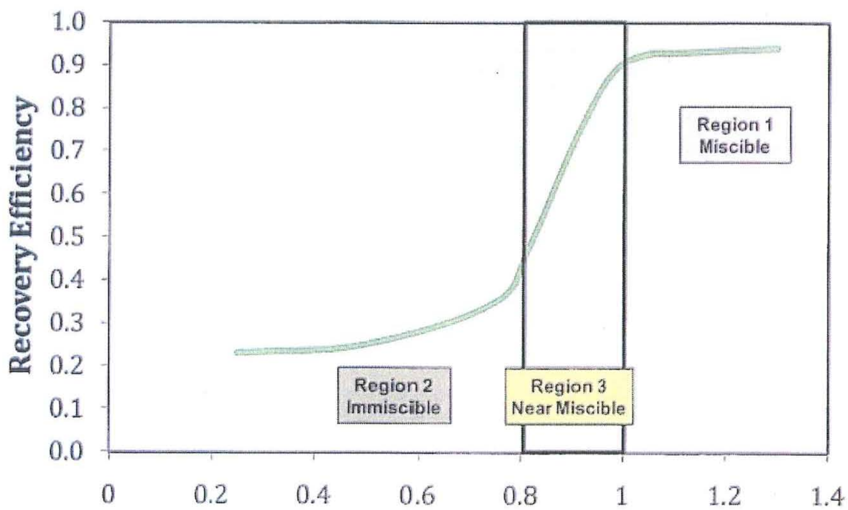
4. Oil Recovery with Near Miscible CO_2-EOR

Figure IV-8 provides the classical oil recovery versus pressure for a slim tube experiment of CO_2 injection. It shows that the efficiency of oil recovery begins to increase sharply in the near miscible pressure region, defined in the figure as 80% of minimum miscibility pressure (MMP).

A somewhat more representative experiment is to conduct a core flow test of oil recovery with pressure in the near miscible region. The Kansas study and laboratory tests determined that oil recovery in the near miscibility pressure region (80% to 99% MMP) recovered 65% to 80% of the water flood residual oil in dolomite cores and 45% to 60% of the water flood residual oil in sandstone cores.[13]

[14] Bossie-Codreanu, IFP – March 2009.

Figure IV-8. Relative Miscible Pressure, Pres/MMP



5. Application of Near Miscible CO_2-EOR Technology by This Study

To capture the performance of near miscible CO_2-EOR, the ARI study identified 67 oil reservoirs holding 12 billion barrels of OOIP that had pressures of 75% to 99% of MMP. It then performed *PROPHET2* streamtube reservoir simulations to calculate oil recovery and CO_2 requirements for each of these oil reservoirs. In general, the results were consistent with the above laboratory findings that the closer the reservoir pressure is to MMP, the higher and more efficient is the oil recovery.

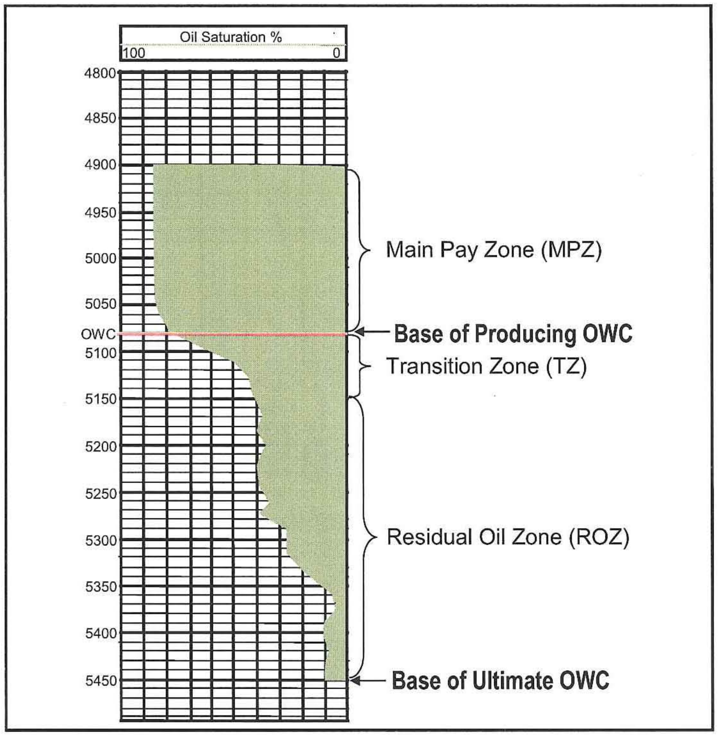
The near miscible reservoirs in the "Next Generation" CO_2-EOR case were flooded with 1 HCPV of CO_2. The residual oil to CO_2 was set at 80% of the residual oil in the reservoir after water flooding to incorporate the extraction/vaporization and lower IFT oil recovery mechanisms inherent within near miscible CO_2-EOR.

C. Application of CO_2-EOR to Residual Oil Zones (ROZs).

The third "Next Generation" CO_2-EOR technology is the application of miscible CO_2-EOR to the oil resource in residual oil zones. Residual oil zones exist below and beyond the main oil reservoir pay zone, below the traditional oil-water contact, Figure IV-9.

Our own detailed log work and extensive work by others, notably, Mr. L. Stephen Melzer of Melzer Consulting and Dr. Robert Trentham of UT Permian Basin, have confirmed that ROZs hold a massive, previously overlooked oil resource in the Permian and numerous other domestic oil basins.

Figure IV-9. Oil Saturation Profile in the TZ/ROZ: Adapted from a Wasson Denver Unit Well.

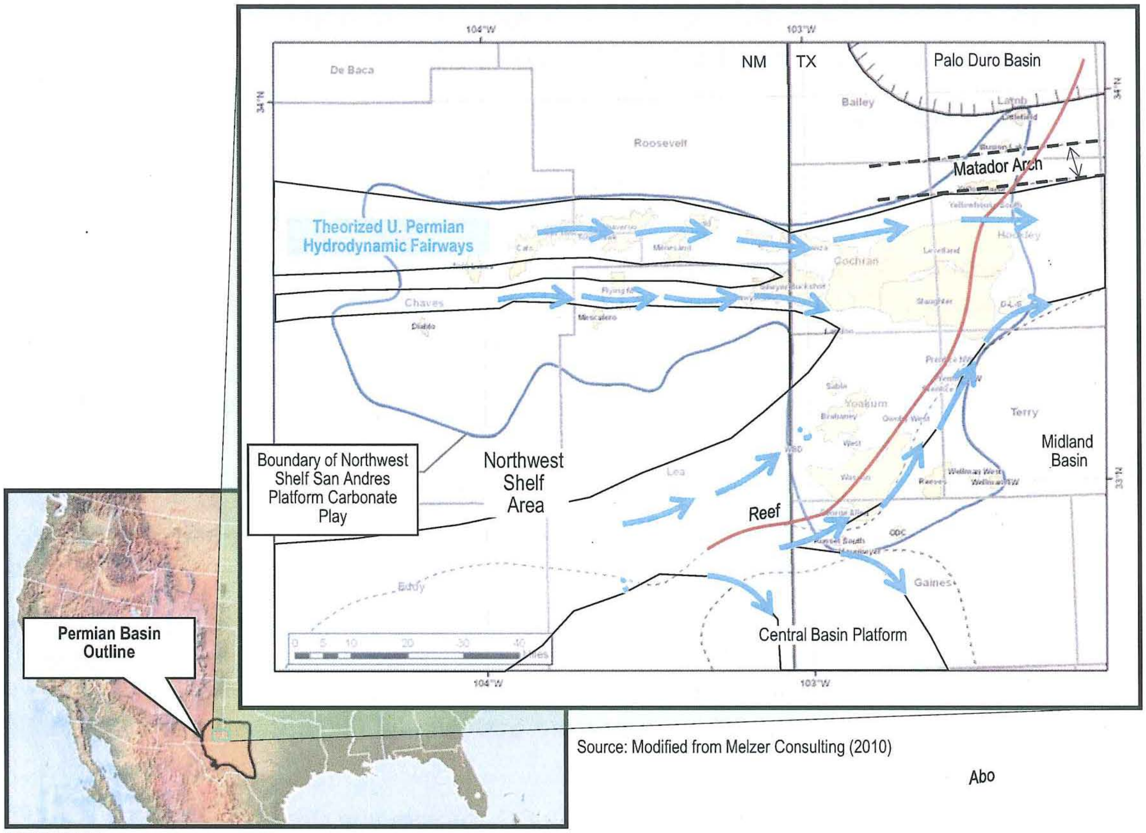


Briefly, residual oil zones exist in the portions of oil reservoirs that have been hydrodynamically swept by the movement of water from outcrop to deeper horizons over a time period of millions of years. One may wish to label this movement of water and its displacement of oil as "nature's waterflood". Because residual oil saturation is low in the naturally water flooded ROZ, CO_2-EOR is required to re-mobilize and recover this oil.

Information from previous reports prepared by Advanced Resources and Melzer Consulting for U.S. DOE/NETL and more recent work by Melzer Consulting for RPSEA show that the ROZ resource occurs well beyond the outlines of existing oil fields and actually exists as a series of areally extensive "ROZ fairways", as illustrated in Figure IV-10. However, because of limitations of scope, the current study only addresses the ROZ resource below the main pay zone within the structural confinement of existing oil fields and does not capture the much larger oil resource within the "ROZ fairways".

While the viability of recovering oil from ROZs is being demonstrated by a series of ROZ field projects (at Seminole by Hess, at Wasson Denver Unit by Occidental, at Goldsmith by Legado, among others), a number of important technical issues remain to be addressed and solved before one can expect optimally efficient oil recovery from ROZs using miscible CO_2-EOR. Some of the technical challenges are discussed in the three ROZ basin studies cited previously.[3,4,5]

Figure IV-10. Map of ROZ Fairways.



Source: Modified from Melzer Consulting (2010)

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D. Deployment of CO_2-EOR in Offshore Oil Fields

The deep, light oils common to Gulf of Mexico (GOM) offshore oil fields are particularly amenable to miscible CO_2-EOR technology. And, with the continued discovery and development of oil fields in the deep waters of the Outer Continental Shelf, the size of this resource target continued to grow.

However, the deployment of CO_2-EOR technology in offshore oil fields faces many barriers and challenges, including inadequate platform space for CO_2 recycling equipment, the expense of drilling new CO_2 injection wells, and the need to transport of CO_2 from onshore sources to offshore platforms. While these barriers and challenges can be addressed, they add substantial costs to the oil recovery process.

While CO_2-EOR projects have been undertaken, in a small handful of offshore oil fields near to shore and in shallow GOM waters, none are currently operating. As such, the fourth "Next Generation" CO_2-EOR technology involves undertaking the challenge of deploying innovative designs and advanced CO_2-EOR technology for offshore oil fields.

V. USING CO_2 ENHANCED OIL RECOVERY (CO_2-EOR) TO INCREASE DOMESTIC OIL PRODUCTION AND TO ACCELERATE DEPLOYMENT OF CCS

A. *Overview of Benefits*

Numerous benefits stem from using captured CO_2 emissions from power and industrial plants for enhanced oil recovery. The most compelling of the numerous benefits include:

- ***Improved Domestic Energy Security***. The implementation of "Next Generation" CO_2-EOR technology, including productively using captured CO_2 emissions from power plants, would enable an additional 67 billion barrels of domestic oil to be economically recovered. This would support 4 million barrels per day of additional oil production by year 2030, greatly improving domestic energy security.

- ***Increased Revenue Streams***. The sale and use of captured CO_2 would provide revenue streams to the capturer of CO_2 emissions and to other entities involved in the CO_2 value chain.

- ***Accelerated Deployment of CCS***. Selection of EOR as the CO_2 storage option would enable major CCS projects to be implemented in the near-term (next ten years) while the "thorny issues" surrounding using saline formations for storing CO_2 (e.g., pore space rights, regulatory approval, public acceptance) are resolved.

These three benefits of integrating CO_2-EOR with CO_2 capture and storage are further discussed below.

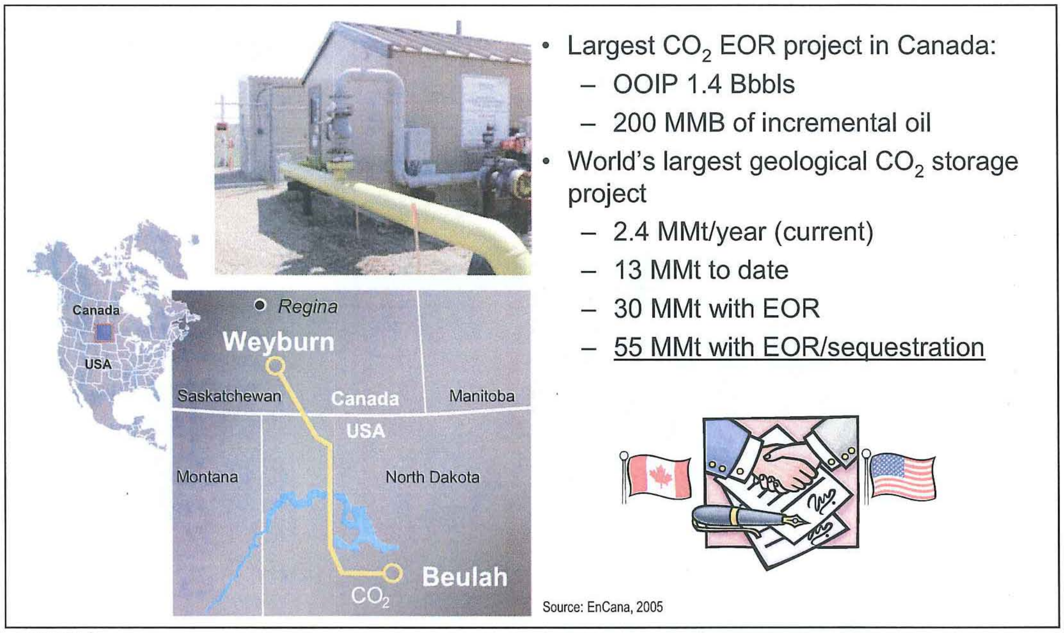
The "poster child" for integrating CO_2-EOR and CO_2 storage, the Weyburn oil field, provides a real world demonstration of the oil recovery and CO_2 storage benefits offered by integrated CO_2-EOR and CO_2 sequestration, Figure V-1. For example:

- The volume of oil recovery is estimated at 200 million barrels, adding to Canadian energy security.

- The purchase of CO_2 by EnCana (now Cenovus) is providing valuable revenues to the Coal Gasification Plant at Beulah, North Dakota. The production of oil is providing royalties and economic activity for the Province of Saskatchewan.

- The storage of CO_2 while recovering the 200 million barrels of oil is estimated at 55 million metric with integrated EOR and CO_2 sequestration.

Figure V-1 "Poster Child" for Integrating CO_2-EOR and CO_2 Storage



Source: EnCana, 2005

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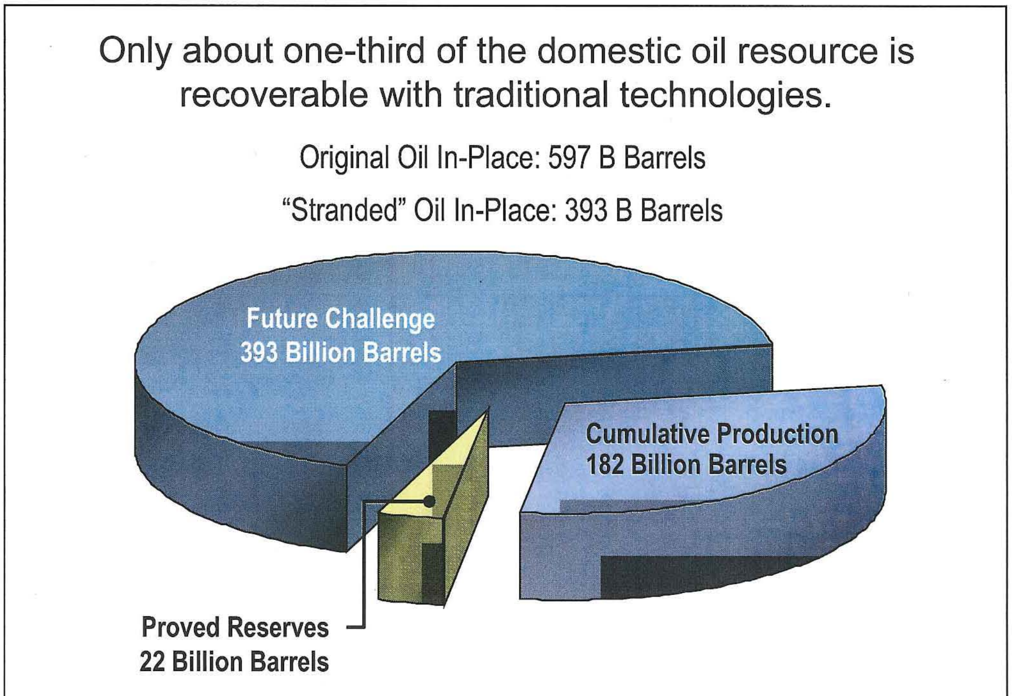
1. Improving Energy Security by Using CO_2-EOR to Increase Domestic Oil Production.

The U.S. uses 19 million barrels of oil per day (about 7 billion barrels per year) primarily to power its massive transportation fleet. Nearly two-thirds of this oil is imported, from countries such as Canada, Mexico, the Middle East and other sources. These large and growing imports impact our energy security, the size of our trade deficit, and the health of our economy.

While still a significant oil producer -- the U.S. produced about 7 million barrels of oil per day (including crude oil, condensate and natural gas liquids) last year -- domestic oil production has been steadily declining. (The recent development of the Bakken Shale has helped stem the oil production decline.)

Yet, the nation has a vast resource of nearly 400 billion barrels of oil still left in the ground ("stranded") that is unrecoverable with existing primary and secondary oil recovery technologies, Figure V-2. Recovering a portion of this "stranded" oil is the goal of the CO_2-EOR technologies clustered under the "Next Generation" technology umbrella.

Figure V-2. The Domestic Oil Resource Base



Source: Advanced Resources Int'l. (2009)

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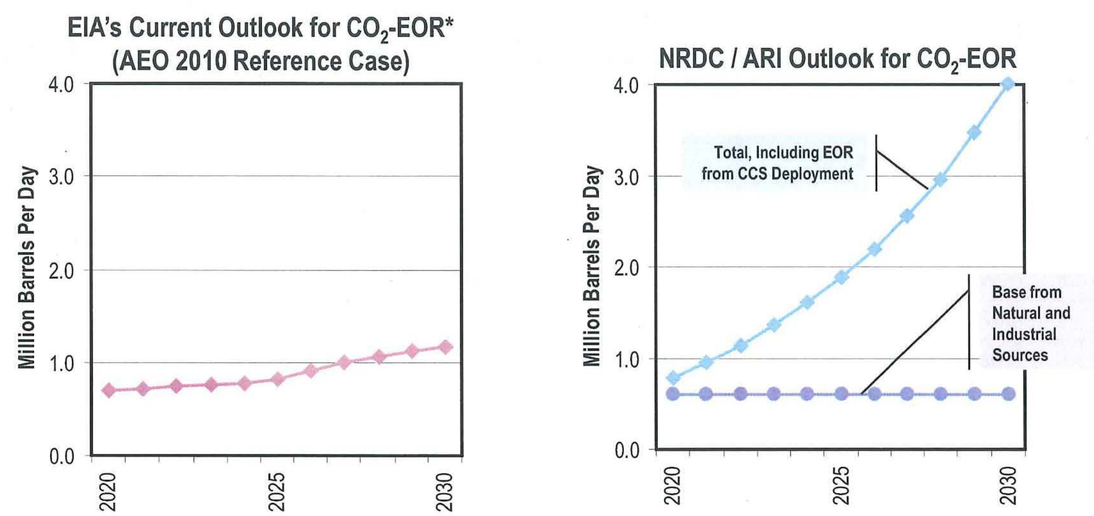
A recent report, prepared for the Natural Resources Defense Council by Advanced Resources International, entitled "U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage[15], states that combining CCS with enhanced oil recovery could boost U.S. oil production by 3.4 million barrels per day by year 2030, Figure V-3. This would be in addition to CO_2-EOR production of about 0.6 million barrels per day from use of currently available CO_2 supplies from natural sources and gas processing plants.

Achieving the total of 4 million barrels per day of oil production from CO_2-EOR, with 3.4 million barrels per day directly linked to use of CO_2 from CCS, would significantly reduce oil imports. It would also reduce annual CO_2 emissions by nearly 400 million metric tons in year 2030.

[15] Advanced Resources International, Inc., "U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage", prepared for the Natural Resources Defense Council, March 2010. This report draws heavily from the U.S. DOE/NETL-sponsored report, also prepared by Advanced Resources "Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology: An Update" Publication Number: DOE/NETL-2010/1417, April 2010.

Figure V-3. Comparison of NRDC/ARI and EIA's Outlook for CO_2-EOR



*Discussions are underway among the U.S. EIA, U.S. DOE/NETL and the NRDC staff on how to represent the integration of CO_2–EOR and CCS in energy market forecasts.

Source: Advanced Resources International, Inc. (2011).

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2. Providing Revenue Streams from Sale of CO_2 and Production of Oil.

A most important benefit from integrating CO_2-EOR and CO_2 storage is that use of CO_2 for oil recovery would provide new revenue streams to a series of notable stakeholders, Table V-1:

- An important revenue stream accrues to the capturers of CO_2 emissions, helping lower the overall cost of conducting CCS. In this report, we assume a price for CO_2 of $40/metric ton, delivered to the oil field at pressure. At 0.3 metric tons of purchased (net) CO_2 per barrel of recovered oil, this results in a transfer of $12 of the $85 per barrel oil to entities selling the CO_2 to the oil industry. Power and other industries involved with CO_2 capture would need to provide nearly 90% of the future CO_2 demand, gaining $730 billion dollars of revenues.

- A second revenue stream accrues to local and state governments and the Federal Treasury from royalties, severance and ad valorem taxes and income taxes. Our analysis shows that, at an oil price of $85 per barrel, $21.20 of this oil price is transferred directly to state and local governments and the Federal Treasury. With 67.2 billion barrels of economically recoverable oil from applying "Next Generation" CO_2-EOR, this equals $1,420 billion of revenues transferred to domestic public treasuries rather than to foreign treasuries. These revenues, in states such as Texas, Wyoming and others, are a primary source of funds for school systems and other valuable public services.

Table V-1. Distribution of Economic Value of Incremental Oil Production from CO_2-EOR

Notes		Oil Industry	Private Minerals	Federal/ State	Power Plant/Other	U.S. Economy
1	**Domestic Oil Price ($/B)**	**$85.00**				
2	Less: Royalties	($14.90)	$12.40	$2.50		
3	Production Taxes	($3.50)	($0.60)	$4.10		
4	CO2 Purchase Costs	($12.00)			$10.80	$1.20
5	CO2 Recycle Costs	($9.60)				$9.60
6	O&M/G&A Costs	($9.00)				$9.00
7	CAPEX	($6.00)				$6.00
	Total Costs	**($55.00)**			-	
	Net Cash Margin	**$30.00**	**$11.80**	**$6.60**	**$10.80**	**$25.80**
8	**Income Taxes**	**($10.50)**	**($4.10)**	**$14.60**	**?**	**?**
	Net Income ($/B)	**$19.50**	**$7.70**	**$21.20**	-	

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1 Assumes $85 per barrel of oil.
2 Royalties are 17.5%; 1 of 6 barrels produced are from federal and state lands.
3 Production and ad valorem taxes of 5%, from FRS data.
4 CO_2 market price of $40/tonne, including transport; 0.3 tonne of purchased CO_2 per barrel of oil; CCS would provide about 90% of CO_2 demand.
5 CO_2 recycle cost of $16/tonne; 0.6 tonnes of recycled CO_2 per barrel of oil.
6 O&M/G&A costs from ARI CO_2-EOR cost models.
7 CAPEX from ARI CO_2-EOR cost models.
8 Combined Federal and state income taxes of 35%, from FRS data.

- A third revenue stream accrues to the general domestic economy from successful application of CO_2-EOR technology. With $25.80 of the $85 barrel oil price being spent on domestic wages and purchases, this provides $1.7 trillion dollars of gross revenues to the domestic economy.
- A fourth revenue stream accrues to a variety of entities holding private mineral rights from royalty payments ($7.70 per barrel) and to the U.S. oil industry ($19.50 per barrel) for return of and return on capital investment. The Texas economic model shows that every dollar of direct investment in oil development has a multiplier of 4 in terms of supporting economic activity.
- Finally, the domestic trade balance (foreign debt) from producing 67.2 billion barrels of domestic oil rather than importing this oil would be reduced by $5.7 trillion.

3. Accelerating the Application of CO_2 Storage.

The integration of CO_2-EOR and CCS would greatly help accelerate the regulatory acceptance and implementation of CO_2 storage:

- Oil fields provide CO_2 storage options that can be permitted under existing (or slightly modified) regulatory guidelines, thereby avoiding the large delays inherent when waiting on new regulations and permitting for large-scale storage of CO_2 in saline formations.
- The pore space, mineral rights and long-term liability issues of oil fields are already well established and thus would not be impediments to an integrated CO_2 storage and CO_2-EOR project.
- Oil fields generally have existing subsurface data and often possess usable infrastructure such as injection wells and gathering systems, enabling more accurate assessment of CO_2 storage capacity and substantial cost savings.

Beyond these three benefits, a number of other conditions favor the use of oil fields for injecting and storing CO_2. First, oil fields are located in areas with an accepted history of subsurface field activities contributing to public acceptance for storing CO_2. Second, oil fields provide an existing "brown field" storage site versus having to establish a new "green field" site when preparing a saline formation for CO_2 storage. Third, the footprint of the CO_2 plume within an oil field would be several times smaller than within a saline formation. Finally, the early reliance on EOR for storing CO_2 would help build the regional pipeline infrastructure for future CO_2 storage projects in saline formations.

B. Proposed Use of Oil Fields for Storing CO_2

To a large extent, industrial operators of proposed coal-to-liquids (CTL) plants, integrated gasification combined cycle (IGCC) facilities, and other carbon conversion projects have already "voted with their feet" for first turning to oil fields for storing CO_2. Three such projects are discussed below[16]:

- Hydrogen Energy's (BP/Rio Tinto) pet-coke gasification plant in Kern County, California plans to deliver 2 MMt/yr of CO_2 to the giant Elk Hills oil field for CO_2-EOR, Figure V-4.
- Southern Company's Kemper County IGCC plant plans to provide 1.1 to 1.5 MMt/yr to Denbury Resources for CO_2-EOR in oil fields in Louisiana and Mississippi, Figure V-5.
- Summit Energy's Texas Clean Energy IGCC project plans to sell 3 MMt/yr for CO_2-EOR in West Texas, Figure V-6.

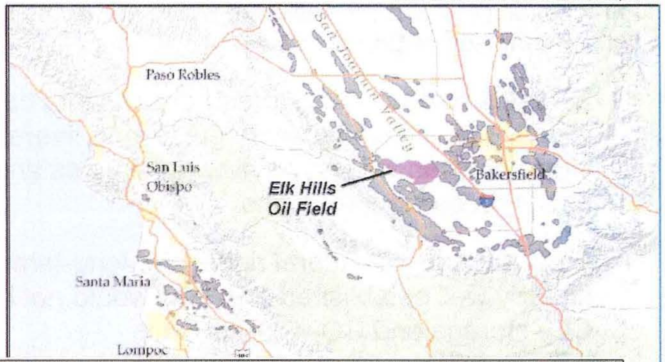
[16] Various industry presentations and publications.

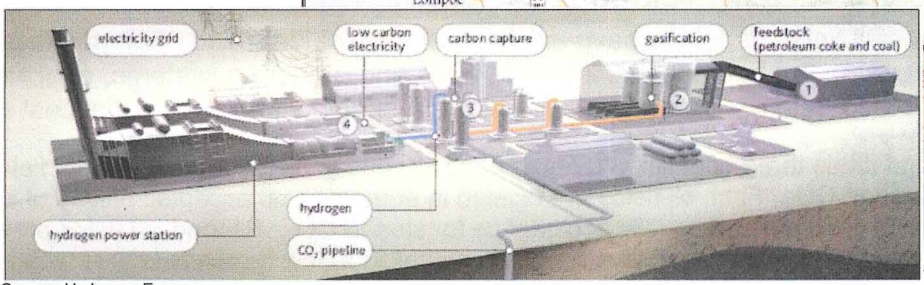
Figure V-4. Advanced Power Plants and Use of EOR for CO_2 Storage

Hydrogen Energy's (Rio Tinto/BP) Pet-coke Gasification Plant

- 250MW gasification of pet-coke
- Capture 90% of CO_2; over 2 million tons of CO_2 per year
- Oxy will take CO_2 for EOR at Elk Hills oil field
- Operational by 2015

Elk Hills Oil Field near Bakersfield, CA





Source: Hydrogen Energy

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Figure V-5. Advanced Power Plants Using EOR for Storage

Southern Company's Kemper County IGCC Plant

- 582 MW IGCC fueled by Mississippi lignite
- Capture 65% of CO_2
- Negotiating to sell 1.1 to 1.5 million tons of CO_2 per year for EOR
- Cost $2.4 B; operational by 2014

*Source: Mississippi Power, Denbury Resources

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Figure V-6. Advanced Power Plants Using EOR for Storage

Summit's Texas Clean Energy IGCC Project

- 400 MW IGCC with 90% capture
- Located near Odessa in Permian Basin
- Sell 3 million tons of CO_2 per year to EOR market
- Expected cost \$1.75 B; \$350 MM award under CCPI Round 3.

Source: Siemens Energy

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* * * * *

Clearly, many of the proposed new IGCC and coal to gas/liquids plants are looking to CO_2-EOR as their primary CO_2 storage option. Because of this, some power companies have expressed concerns that these initial plants will "use up" all of the available EOR market and CO_2 storage capacity, leaving little for subsequent use.

As such, the key questions are: (1) How much CO_2 could be sold to and stored with "Next Generation" CO_2 enhanced oil recovery, and (2) Where are the potential CO_2 demand (and storage) centers? These key questions are addressed in the following chapter.

VI. A REGIONAL ("BASIN-ORIENTED STRATEGY") LOOK AT THE CO_2-EOR/STORAGE POTENTIAL

The CO_2-EOR potential, for both storing CO_2 and producing oil, varies significantly across the regions and basins of the U.S. For example, the great Permian Basin of West Texas and New Mexico, while the "birth place" of CO_2-EOR, still offers major opportunities for applying "Next Generation" CO_2-EOR technology.

Other regions of the country offer similar promise but still face constraints. California, currently locked out of natural CO_2 sources, has a host of deep, light oil reservoirs, such as the giant Elk Hills, ready for development with CO_2-EOR. The giant oil fields in East and South Texas, now with access to supplies of CO_2, are being evaluated for CO_2-EOR as the Green Pipeline beings to deliver CO_2 to the region.

The oil fields in the offshore Gulf of Mexico, while technically attractive for CO_2-EOR miscible flooding, face serious infrastructure and cost constraints. Alaska, with large declining oil fields that could be revitalized with CO_2-EOR, would need to see the launch of the Alaska Natural Gas Pipeline or the installation of a "world scale" energy processing and petrochemicals facility to create sufficient supplies of CO_2.

Chapter VII of the report provides a more detailed look at the oil production and CO_2 storage potential offered by the following eleven regions:

1. Appalachia
2. California
3. East and Central Texas
4. Michigan/Illinois
5. Mid-Continent
6. Permian Basin
7. Rockies
8. Southeast Gulf Coast
9. Williston Basin
10. Alaska
11. Offshore Gulf of Mexico

1. Appalachia

a. Background. The Appalachia Basin, the origin of the U.S. oil industry, provided much of the petroleum used by the U.S. during World War II. Currently, oil production is 12 million barrels per year (about 33,000 barrels per day) from a series of very mature fields (Table V1-1.1).

Table VI-1.1. Crude Oil Production from the Appalachian Basin (MM Bbls/Yr)

Year	New York	Ohio	Pennsylvania	West Virginia	TOTAL
2000	*	7	2	1	10
2001	*	6	2	1	9
2002	*	6	2	1	9
2003	*	6	2	1	9
2004	*	6	3	1	10
2005	*	6	4	2	12
2006	*	5	4	2	11
2007	*	5	4	2	11
2008	*	6	4	2	12
2009	*	6	4	2	12

*less than 0.5 million barrels. Source: EIA Crude Oil Production by State (March 2011).

b. Reservoirs Favorable for CO_2-EOR. Advanced Resources' Big Oil Fields Database for the Appalachian Basin contains 84 oil reservoirs that screen favorably for miscible CO_2-EOR plus 19 oil reservoirs that screen favorably for near miscible CO_2-EOR. These 103 reservoirs contain 9.4 billion barrels of OOIP out of a data base of 171 reservoirs with 10.2 billion of OOIP.

c. Miscible CO_2-EOR.

(1). Database. The data for the 84 Appalachian Basin oil reservoirs favorable for miscible CO_2-EOR are as follows:

Original Oil In-Place	8.6 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	1.5 billion barrels
Primary/Secondary Oil Recovery Efficiency	17%
Remaining Oil In-Place	7.1 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR applied to these 84 oil reservoirs offers the potential for technically recovering 2.4 billion barrels of the remaining oil in-place, equal to 28% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 48 of the 84 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. These 48 reservoirs have an economically feasible oil recovery of 1.3 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 84 Appalachian Basin oil fields technically favorable for miscible CO_2-EOR is 790 million metric tons (15 Tcf). The volume of purchased CO_2 for the 48 Appalachian Basin oil reservoirs economically favorable for miscible CO_2-EOR is 290 million metric tons (5 Tcf).

(5) Summary Table. Table VI-1.2 provides a summary of the oil recovery and CO_2 demand (and storage) potential from the application of miscible "Next Generation" CO_2-EOR in the Appalachian Basin for the data base and extrapolated regional totals.

Table VI-1.2. Appalachian Basin Oil Recovery and CO_2 Demand from Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	2.4	1.3	790	290
2. Regional Totals	3.3	1.3	1,080	290

*Database totals extrapolated to regional totals using a dividing factor of 0.73.

d. Near Miscible CO_2-EOR.

(1). Database. The data for the 19 Appalachian Basin oil reservoirs technically favorable for near miscible CO_2-EOR are as follows:

Original Oil In-Place	0.78 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	0.16 billion barrels
Primary/Secondary Oil Recovery Efficiency	20%
Remaining Oil In-Place	0.62 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR applied to these 19 oil reservoirs offers the potential for technically recovering 0.1 billion barrels of the remaining oil in-place, equal to 8% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), none of the 19 oil reservoirs provide a 20% rate of return (before tax) and thus none are economically feasible.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 19 Appalachian Basin oil fields technically favorable for near miscible CO_2-EOR is 60 million metric tons (1 Tcf).

(5) Summary Table. Table VI-1.3 provides a summary of the oil recovery and CO_2 demand (and storage) potential from the application of near miscible "Next Generation" CO_2-EOR in the Appalachian Basin for the database and extrapolated regional totals.

Table VI-1.3. Appalachian Basin Oil Recovery and CO_2 Demand from Near Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	0.1	-	60	-
2. Regional Totals	0.1	-	80	-

*Database totals extrapolated to regional totals using a dividing factor of 0.73.

e. *Miscible and Near Miscible CO_2-EOR.* Table VI-1.4 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of "Next Generation" CO_2-EOR in the Appalachian Basin.

Table VI-1.4. Appalachian Basin Oil Recovery and CO_2 Demand from "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	2.5	1.3	850	290
2. Regional Totals	3.4	1.3	1,160	290

*Database totals extrapolated to regional totals using a dividing factor of 0.73.

f. Comparison of State of Art and "Next Generation" CO_2-EOR Technology. Using "Next Generation" CO_2-EOR in the Appalachian Basin would provide significantly more oil recovery and CO_2 storage potential than would be realized from applying State of Art CO_2-EOR technology, Table VI-1.5.

- Economic oil recovery would be 1.3 billion barrels with "Next Generation" technology compared to essentially zero with State of Art technology.
- Economic CO_2 demand (and storage capacity) would be 290 million metric tons with "Next Generation" technology compared to about 10 million metric tons with State of Art technology.

Table VI-1.5. Summary Table of Comparison of State of Art and "Next Generation" CO_2-EOR Technology: Appalachian Basin (Regional Totals)

		State of Art	"Next Generation"
Oil Recovery (Billion Barrels)			
	▪ Technical	1.1	3.4
	▪ Economic	0.0	1.3
CO_2 Demand (Million Metric Tons)			
	▪ Technical	520	1,160
	▪ Economic	10	290

2. *Onshore California*

a. Background. While much of the oil production from California is due to steam injection for heavy oil recovery, California (particularly the San Joaquin Basin) does have large, deep light oil reservoirs (such as Elk Hills) that account for an important part of California's oil production. In 2009, California produced 194 million barrels (530,000 barrels per day) of heavy and light oil (Table VI-2.1).

Table VI-2.1. Oil Production from Onshore California (MM Bbls/Yr)

Year	Coastal	Los Angeles	San Joaquin	TOTAL
2000	18	16	215	249
2001	18	16	220	238
2002	18	17	205	240
2003	17	16	197	230
2004	17	16	191	224
2005	15	16	184	215
2006	15	16	176	207
2007	15	17	173	205
2008	16	16	175	207
2009	18	15	161	194

Sources: EIA Proved Reserves and Production (December, 2010) and EIA Crude Oil Production by State (March 2011).

b. Reservoirs Favorable for CO_2-EOR. Advanced Resources' Big Oil Fields Database for California contains 76 oil reservoirs that screen favorably for miscible CO_2-EOR plus 13 oil reservoirs that screen favorably for near miscible CO_2-EOR. These 89 reservoirs contain 31.9 billion barrels of OOIP out of a data base of 187 reservoirs with 74.6 billion of OOIP.

c. *Miscible CO_2-EOR.*

(1). Database. The data for the 76 California oil reservoirs favorable for miscible CO_2-EOR are as follows:

Original Oil In-Place	28.2 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	8.8 billion barrels
Primary/Secondary Oil Recovery Efficiency	31%
Remaining Oil In-Place	19.4 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 76 oil reservoirs offers the potential for technically recovering 6.9 billion barrels of the remaining oil in-place, equal to 25% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 69 of the 76 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. The economically feasible oil recovery is 6.5 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 76 California oil fields technically favorable for miscible CO_2-EOR is 1,940 million metric tons (37 Tcf). The volume of purchased CO_2 for the 69 California oil reservoirs economically favorable for miscible CO_2-EOR is 1,690 million metric tons (32 Tcf).

(5) Summary Table. Table VI-2.2 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of miscible "Next Generation" CO_2-EOR in California and extrapolated to regional totals.

Table VI-2.2. Onshore California Oil Recovery and CO_2 Demand from Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	6.9	6.5	1,940	1,690
2. Regional Totals	7.7	6.5	2,160	1,690

*Database totals extrapolated to regional totals using a dividing factor of 0.90.

d. Near Miscible CO_2-EOR.

(1). Database. The data for the 13 California oil reservoirs favorable for near miscible CO_2-EOR are as follows:

Original Oil In-Place	3.7 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	1.1 billion barrels
Primary/Secondary Oil Recovery Efficiency	31%
Remaining Oil In-Place	2.6 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 13 oil reservoirs offers the potential for technically recovering 0.2 billion barrels of the remaining oil in-place, equal to 5% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 2 of the 13 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. The economically feasible oil recovery is 0.2 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 13 California oil fields technically favorable for near miscible CO_2-EOR is 140 million metric tons (3 Tcf). The volume of purchased CO_2 for the 2 California oil reservoirs economically favorable for near miscible CO_2-EOR is 70 million metric tons (1Tcf).

(5) Summary Table. Table VI-2.3 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of near miscible "Next Generation" CO_2-EOR in California.

Table VI-2.3. Onshore California Oil Recovery and CO_2 Demand from Near Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	**Economic**	**Technical***	**Economic**
1. Database Totals	0.2	0.2	140	70
2. Regional Totals	0.2	0.2	160	70

*Database totals extrapolated to regional totals using a dividing factor of 0.90.

e. Miscible and Near Miscible CO_2-EOR. Table VI-2.4 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of "Next Generation" CO_2-EOR in California.

Table VI-2.4. Onshore California Oil Recovery and CO_2 Demand from "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	**Economic**	**Technical***	**Economic**
1. Database Totals	7.1	6.7	2,080	1,760
2. Regional Totals	7.9	6.7	2,320	1,760

*database totals extrapolated to regional totals using a dividing factor of 0.90.

f. Comparison of State of Art and "Next Generation" CO_2-EOR Technology.
Applying "Next Generation" CO_2-EOR in California would provide valuable additional oil recovery and CO_2 storage, Table VI-2.5.

- Economic oil recovery would be 6.7 billion barrels with "Next Generation" technology compared to 1.2 billion barrels with State of Art technology.
- Economic CO_2 demand (and storage capacity) would be 1,760 million metric tons with "Next Generation" technology compared to 480 million metric tons with State of Art technology.

Table VI-2.5. Summary Table of Comparison of State of Art and "Next Generation" CO_2-EOR Technology: Onshore California (Regional Totals)

		State of Art	"Next Generation"
Oil Recovery (Billion Barrels)			
	▪ Technical	3.1	7.9
	▪ Economic	1.2	6.7
CO_2 Demand (Million Metric Tons)			
	▪ Technical	1,340	2,320
	▪ Economic	480	1,760

3. *East and Central Texas*

a. Background. East Texas ushered in the "oil boom" at historic oil fields such as Spindletop and Conroe. Today, this area provides 114 million barrels of oil per year (about 310,000 barrels per day) (Table VI-3.1).

Table VI-3.1. Oil Production from East and Central Texas (MM Bbls/Yr)

Year	East Texas (RR #1-6)	Central Texas (RR 7B/7C and 9-10)	TOTAL
2000	93	56	149
2001	78	53	131
2002	71	48	119
2003	67	48	115
2004	66	46	112
2005	64	45	109
2006	66	49	115
2007	64	49	113
2008	61	55	116
2009	55	59	114

Source: EIA Proved Reserves and Production (December, 2010).

b. Summary of Results. Advanced Resources' Big Oil Fields Database for East and Central Texas contains 186 oil reservoirs that screen favorably for miscible CO_2-EOR plus 7 oil reservoirs that screen favorably for near miscible CO_2-EOR. These 193 reservoirs contain 61.1 billion barrels of OOIP out of a data base of 213 reservoirs with 66.4 billion barrels of OOIP.

c. Miscible CO_2-EOR.

(1). Database. The data for the 186 East and Central Texas oil reservoirs favorable for miscible CO_2-EOR are as follows:

Original Oil In-Place	59.4 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	21.2 billion barrels
Primary/Secondary Oil Recovery Efficiency	36%
Remaining Oil In-Place	38.2 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 186 oil reservoirs offers the potential for technically recovering 15.3 billion barrels of the remaining oil in-place, equal to 26% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 162 of the 186 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. The economically feasible oil recovery is 13.5 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 demand for the 186 East and Central Texas oil fields technically favorable for miscible CO_2-EOR is 4,390 million metric tons (83 Tcf). The volume of purchased CO_2 demand for the 162 East and Central Texas oil reservoirs economically favorable for miscible CO_2-EOR is 3,620 million metric tons (68 Tcf).

Subtracting out the 400 million metric tons (8 Tcf) of CO_2 expected to be delivered to East Texas from natural sources still leaves a near- to mid-term economic market for purchase (and storage) of anthropogenic CO_2 of 3,220 million metric tons (60 Tcf).

(5) Summary Table. Table VI-3.2 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of miscible "Next Generation" CO_2-EOR in East and Central Texas.

Table VI-3.2. East and Central Texas Oil Recovery and CO_2 Demand from Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)**	
	Technical*	Economic	Technical*	Economic
1. Database Totals	15.3	13.5	4,390	3,620
2. Regional Totals	20.7	13.5	5,930	3,620

*Database totals extrapolated to regional totals using a dividing factor of 0.74.
**Includes 580 million metric tons of CO_2 demand expected to be provided by natural sources and gas processing plants.

d. Near Miscible CO_2-EOR.

(1). Database. The data for the 7 East and Central Texas oil reservoirs favorable for near miscible CO_2-EOR are as follows:

Original Oil In-Place	1.8 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	0.5 billion barrels
Primary/Secondary Oil Recovery Efficiency	26%
Remaining Oil In-Place	1.3 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 7 oil reservoirs offers the potential for technically recovering 0.12 billion barrels of the remaining oil in-place, equal to 7% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), none of the oil reservoirs provide at least a 20% rate of return (before tax) and thus none are economically feasible.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 7 East and Central Texas oil fields technically favorable for near miscible CO_2-EOR is 80 million metric tons (2 Tcf).

(5) Summary Table. Table VI-3.3 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of near miscible "Next Generation" CO_2-EOR in East and Central Texas.

Table VI-3.3. East and Central Texas Oil Recovery and CO_2 Demand from Near Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	0.1	-	80	-
2. Regional Totals	0.2	-	110	-

*Database totals extrapolated to regional totals using a dividing factor of 0.74.

e. Miscible and Near Miscible CO_2-EOR. Table VI-3.4 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of "Next Generation" CO_2-EOR in East and Central Texas.

Table VI-3.4. East and Central Texas Oil Recovery and CO_2 Storage from "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)**	
	Technical*	Economic	Technical*	Economic
1. Database Totals	15.4	13.5	4,470	3,620
2. Regional Totals	20.9	13.5	6,040	3,620

*Database totals extrapolated to regional totals using a dividing factor of 0.74.
**Includes 400 million metric tons of CO_2 demand provided from natural sources.

f. Comparison of State of Art and "Next Generation" CO_2-EOR Technology. Applying "Next Generation" CO_2-EOR in East and Central Texas would provide valuable additional oil recovery and CO_2 storage (Table VI-3.5).

- Economic oil recovery would be 13.5 billion barrels with "Next Generation" technology compared to 5.9 billion barrels with State of Art technology.
- Economic CO_2 demand (and storage capacity) would be 3,620 million metric tons with "Next Generation" technology compared to 2,120 million metric tons (gross) with State of Art technology.

Table VI-3.5. Summary Table of Comparison of State of Art and "Next Generation" CO_2-EOR Technology: East and Central Texas

		State of Art	"Next Generation"
Oil Recovery (Billion Barrels)			
	▪ Technical	11.1	20.9
	▪ Economic	5.9	13.5
CO_2 Demand (Million Metric Tons)			
	▪ Technical	4,210	6,040
	▪ Economic		
	– Gross*	2,120	3,620
	– Net	1,720	3,220

* Includes 400 million metric tons of CO_2 demand expected to be provided by natural sources and gas processing plants.

4. Michigan/Illinois Basin

a. Background. The mature Michigan and Illinois oil basins have seen a steady decline in production in recent years, reaching 20 million barrels per year (about 55,000 barrels per day) in 2009 (Table VI-4.1).

Table VI-4.1. Oil Production from Michigan and Illinois Basins (MM Bbls/Yr)

Year	Michigan	Illinois/Indiana	Kentucky	TOTAL
2000	8	14	3	25
2001	7	12	3	22
2002	7	14	3	24
2003	7	14	3	24
2004	6	12	3	21
2005	6	12	2	20
2006	5	12	3	20
2007	5	11	3	19
2008	6	11	3	20
2009	6	11	3	20

Source: EIA Crude Oil Production by State (March 2011).

b. Summary of Results. Advanced Resources' Big Oil Fields Database for Michigan/Illinois Basin contains 140 oil reservoirs that screen favorably for miscible CO_2-EOR plus 8 oil reservoirs that screen favorably for near miscible CO_2-EOR. These 148 reservoirs contain 9.8 billion barrels of OOIP out of a data base of 190 reservoirs with 10.2 billion barrels of OOIP.

c. Miscible CO_2-EOR.

(1). Database. The data for the 140 Michigan/Illinois Basin oil reservoirs favorable for miscible CO_2-EOR are as follows:

Original Oil In-Place	8.4 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	3.2 billion barrels
Primary/Secondary Oil Recovery Efficiency	38%
Remaining Oil In-Place	5.2 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 140 oil reservoirs offers the potential for technically recovering 2.1 billion barrels of the remaining oil in-place, equal to 25% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 122 of the 140 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. The economically feasible oil recovery is 1.8 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 140 Michigan/Illinois Basin oil fields technically favorable for miscible CO_2-EOR is 710 million metric tons (13 Tcf). The volume of purchased CO_2 for the 122 Michigan/Illinois Basin oil reservoirs economically favorable for miscible CO_2-EOR is 570 million metric tons (11 Tcf).

(5) Summary Table. Table VI-4.2 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of miscible "Next Generation" CO_2-EOR in Michigan/Illinois Basin.

Table VI-4.2. Michigan/Illinois Basin Oil Recovery and CO_2 Demand from Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	2.1	1.8	710	570
2. Regional Totals	2.8	1.8	960	570

*Database totals extrapolated to regional totals using a dividing factor of 0.74.

d. Near Miscible CO_2-EOR.

(1). Database. The data for the 8 Michigan/Illinois Basin oil reservoirs favorable for near miscible CO_2-EOR are as follows:

Original Oil In-Place	1.3 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	0.4 billion barrels
Primary/Secondary Oil Recovery Efficiency	32%
Remaining Oil In-Place	0.9 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 8 oil reservoirs offers the potential for technically recovering 0.1 billion barrels of the remaining oil in-place, equal to 10% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), none of the oil reservoirs provide at least a 20% rate of return (before tax) and thus none are economically feasible.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 8 Michigan/Illinois Basin oil fields technically favorable for near miscible CO_2-EOR is 70 million metric tons (1 Tcf).

(5) Summary Table. Table VI-4.3 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of near miscible "Next Generation" CO_2-EOR in the Michigan/Illinois Basin.

Table VI-4.3. Michigan/Illinois Basin Oil Recovery and CO_2 Demand from Near Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	0.1	-	70	0
2. Regional Totals	0.2	-	90	0

*Database totals extrapolated to regional totals using a dividing factor of 0.74.

e. Miscible and Near Miscible CO_2-EOR. Table VII-4.4 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of "Next Generation" CO_2-EOR in the Michigan/Illinois Basin.

Table VI-4.4. Michigan/Illinois Basin Oil Recovery and CO_2 Demand from "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	2.2	1.8	780	570
2. Regional Totals	3.0	1.8	1,050	570

*Database totals extrapolated to regional totals using a dividing factor of 0.74.

f. Comparison of State of Art and "Next Generation" CO_2-EOR Technology. Applying Next Generation CO_2-EOR in the Michigan/Illinois Basin would provide valuable additional oil recovery and CO_2 storage (Table VI-4.5).

- Economic oil recovery would be 1.8 billion barrels with "Next Generation" technology compared to 1.1 billion barrels with State of Art technology.
- Economic CO_2 demand (and storage capacity) would be 570 million metric tons with "Next Generation" technology compared to 390 million metric tons with State of Art technology.

Table VI-4.5. Summary Table of Comparison of State of Art and "Next Generation" CO_2-EOR Technology: Michigan/Illinois Basin

		State of Art	"Next Generation"
Oil Recovery (Billion Barrels)			
	▪ Technical	1.8	3.0
	▪ Economic	1.1	1.8
CO_2 Demand (Million Metric Tons)			
	▪ Technical	660	1,050
	▪ Economic	390	570

5. *Mid-Continent*

a. Background. After years of steady decline, oil production in the Mid-Content area, particularly in Oklahoma, has begun to rebound reaching 115 million barrels per year (315,000 barrels per day) in 2009 (Table VI-5.1).

Table VI-5.1. Oil Production from the Mid-Continent (MM Bbls/Yr)

Year	Oklahoma	Kansas/Nebraska	Arkansas	TOTAL
2000	70	37	7	114
2001	69	37	8	114
2002	67	36	7	110
2003	65	37	7	109
2004	62	36	7	105
2005	62	36	6	104
2006	63	38	6	107
2007	61	39	6	106
2008	64	42	6	112
2009	67	42	6	115

Source: EIA Crude Oil Production by State (March 2011).

b. Summary of Results. Advanced Resources' Big Oil Fields Database for the Mid-Continent contains 174 oil reservoirs that screen favorably for miscible CO_2-EOR plus 9 oil reservoirs that screen favorably for near miscible CO_2-EOR. These 183 reservoirs contain 46.0 billion barrels of OOIP out of a database of 246 reservoirs with 53.1 billion of OOIP.

c. Miscible CO_2-EOR.

(1). Database. The data for the 174 the Mid-Continent oil reservoirs favorable for miscible CO_2-EOR are as follows:

Original Oil In-Place	43.7 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	12.0 billion barrels
Primary/Secondary Oil Recovery Efficiency	27%
Remaining Oil In-Place	31.7 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 174 oil reservoirs offers the potential for technically recovering 13.1 billion barrels of the remaining oil in-place, equal to 30% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 154 of the 174 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. The economically feasible oil recovery from these reservoirs is 11.9 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 174 Mid-Continent oil fields technically favorable for miscible CO_2-EOR is 3,740 million metric tons (71 Tcf). The volume of purchased CO_2 for the 154 Mid-Continent oil reservoirs economically favorable for miscible CO_2-EOR is 3,240 million metric tons (61 Tcf).

(5) Summary Table. Table VI-5.2 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of miscible "Next Generation" CO_2-EOR in Mid-Continent.

Table VI-5.2. Mid-Continent Oil Recovery and CO_2 Demand from Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	13.1	11.9	3,740	3,240
2. Regional Totals	22.2	11.9	6,340	3,240

*Database totals extrapolated to regional totals using a dividing factor of 0.59.

d. Near Miscible CO_2-EOR.

(1). Database. The data for the 9 Mid-Content oil reservoirs favorable for near miscible CO_2-EOR are as follows:

Original Oil In-Place	2.3 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	0.6 billion barrels
Primary/Secondary Oil Recovery Efficiency	28%
Remaining Oil In-Place	1.7 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 9 oil reservoirs offers the potential for technically recovering 0.17 billion barrels of the remaining oil in-place, equal to 7% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 2 of the 9 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. The economically feasible oil recovery is 0.1 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 9 Mid-Continent oil fields technically favorable for near miscible CO_2-EOR is 110 million metric tons (2 Tcf). The volume of purchased CO_2 for the 2 Mid-Continent oil reservoirs economically favorable for near miscible CO_2-EOR is 30 million metric tons (1 Tcf).

(5) Summary Table. Table VI-5.3 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of near miscible "Next Generation" CO_2-EOR in the Mid-Content.

Table VI-5.3. Mid-Content Oil Recovery and CO_2 Demand from Near Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	0.2	0.1	110	30
2. Regional Totals	0.3	0.1	190	30

*Database totals extrapolated to regional totals using a dividing factor of 0.59.

e. Miscible and Near Miscible CO_2-EOR. Table VI-5.4 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of "Next Generation" CO_2-EOR in the Mid-Continent.

Table VI-5.4. Mid-Continent Oil Recovery and CO_2 Demand from "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	13.3	12.0	3,850	3,270
2. Regional Totals	22.5	12.0	6,530	3,270

*Database totals extrapolated to regional totals using a dividing factor of 0.59.

f. Comparison of State of Art and "Next Generation" CO_2-EOR Technology. Applying "Next Generation" CO_2-EOR in the Mid-Continent would provide valuable additional oil recovery and CO_2 storage (Table VI-5.5).

- Economic oil recovery would be 12.0 billion barrels with "Next Generation" technology compared to 6.6 billion barrels with State of Art technology.
- Economic CO_2 demand (and storage capacity) would be 3,270 million metric tons with "Next Generation" technology compared to 2,120 million metric tons with State of Art technology.

Table VI-5.5. Summary Table of Comparison of State of Art and "Next Generation" CO_2-EOR Technology: Mid-Continent (Regional Totals)*

		State of Art	"Next Generation"
Oil Recovery (Billion Barrels)*			
	▪ Technical	12.9	22.5
	▪ Economic	6.6	12.0
CO_2 Demand (Million Metric Tons)			
	▪ Technical	4,220	6,530
	▪ Economic	2,120	3,270

*Includes 0.1 billion barrels already produced or proven with miscible CO_2-EOR technology.

6. *Permian Basin*

a. Background. The Permian Basin, located in West Texas (Texas Railroad Districts 8 and 8A) and East New Mexico, is still one of the largest oil producing regions of the world. In 2009, this area with 289 million barrels of oil production (790 thousand barrels per day) ranked first for U.S. oil production. To date, the Permian Basin has produced 32 billion barrels of oil with 4.8 billion barrels of remaining proved reserves. (These values include production and proved reserves from applying CO_2-EOR). Table VI-6.1 provides a tabulation of recent oil production rates for the Permian Basin as well as separately for West Texas and East New Mexico.

Table VI-6.1. Oil Production from the Permian Basin (MM Bbls/Yr)

Year	West Texas [1]	East New Mexico [2]	TOTAL
2000	259	66	325
2001	258	67	325
2002	248	66	314
2003	248	65	313
2004	245	63	308
2005	245	60	305
2006	240	59	299
2007	237	58	295
2008	232	58	290
2009	229	60	289

Sources: [1] EIA Proved Reserves and Production (December, 2010); [2] EIA Crude Oil Production by State (March, 2011)

The Permian Basin contains numerous large, deep, light oil fields and reservoirs attractive for CO_2 enhanced oil recovery. The oil fields are mature and, except for those under CO_2 enhanced oil recovery, are in steep decline.

b. Summary of Results. Advanced Resources' Big Oil Fields Database for the Permian Basin contains 215 oil reservoirs that screen favorably for miscible CO_2-EOR plus 2 oil reservoirs that screen favorably for near miscible CO_2-EOR. These 217 reservoirs contain 72.2 billion barrels of OOIP out of a database of 228 reservoirs with 72.5 billion OOIP.

c. Miscible CO_2-EOR.

(1). Database. The data for the 215 Permian Basin oil reservoirs favorable for miscible CO_2-EOR are as follows:

Original Oil In-Place	71.0 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	23.3 billion barrels
Primary/Secondary Oil Recovery Efficiency	33%
Remaining Oil In-Place	47.7 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 215 oil reservoirs offers the potential for technically recovering 18.2 billion barrels of the remaining oil in-place, equal to 26% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 151 of the 215 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. Because most of the giant oil fields in this basin, such as Wasson, Slaughter and Seminole, meet the 20% rate of return hurdle, the great bulk of the original oil in-place resource in this basin is in oil fields economic for CO_2-EOR. The economically feasible oil recovery is 14.6 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 215 Permian Basin oil fields technically favorable for miscible CO_2-EOR is 6,490 million metric tons (123 Tcf). The volume of purchased CO_2 for the 151 Permian Basin oil reservoirs economically favorable for miscible CO_2-EOR is 4,750 million metric tons (90 Tcf).

(5) Summary Table. Table VI-6.2 provides a summary of the oil recovery and CO_2 demand from the application of miscible "Next Generation" CO_2-EOR in Permian Basin for the 215 oil reservoirs in the data base and for regional totals.

Table VI-6.2. Permian Basin Oil Recovery and CO_2 Demand from Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand** (Million Metric Tons)	
	Technical*	**Economic**	**Technical***	**Economic**
1. Database Totals	18.2	14.6	6,490	4,750
2. Regional Totals	23.9	14.6	8,540	4,750

*Database totals extrapolated to regional totals using a dividing factor of 0.76.
** Includes 1,730 million metric tons of CO_2 demand expected to be provided by natural sources and gas processing plants.

d. Near Miscible CO_2-EOR.

(1). Database. The data for the 2 Permian Basin oil reservoirs favorable for near miscible CO_2-EOR are as follows:

Original Oil In-Place	1.1 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	0.4 billion barrels
Primary/Secondary Oil Recovery Efficiency	31%
Remaining Oil In-Place	0.8 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 2 oil reservoirs offers the potential for technically recovering 0.1 billion barrels of the remaining oil in-place, equal to 9% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), none of the oil reservoirs provide at least a 20% rate of return (before tax) and thus none are economically feasible.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 2 Permian Basin oil fields technically favorable for near miscible CO_2-EOR is 60 million metric tons (1 Tcf).

(5) Summary Table. Table VI-6.3 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of near miscible "Next Generation" CO_2-EOR in the Permian Basin.

Table VI-6.3. Permian Basin Oil Recovery and CO_2 Demand from Near Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	**Economic**	**Technical***	**Economic**
1. Database Totals	0.1	-	60	-
2. Regional Totals	0.1	-	80	-

*Database totals extrapolated to regional totals using a dividing factor of 0.76.

e. Miscible and Near Miscible CO_2-EOR. Table VI-6.4 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of "Next Generation" CO_2-EOR in the Permian Basin.

Table VI-6.4. Permian Basin Oil Recovery and CO_2 Demand from "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand** (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	18.3	14.6	6,550	4,750
2. Regional Totals	24.0	14.6	8,620	4,750

*Database totals extrapolated to regional totals using a dividing factor of 0.76
**Includes 1,540 million metric tons of CO_2 demand expected to be provided from natural sources and gas processing plants.

Of the 4,750 million metric tons (90 Tcf) of economic CO_2 demand in the Permian Basin, 1,540 million metric tons (29 Tcf) is expected to be provided from natural sources and existing gas processing plants, leaving a net demand of 3,210 million metric tons (61 Tcf) as the market of anthropogenic CO_2, primarily from power plants.

f. Comparison of State of Art and "Next Generation" CO_2-EOR Technology (Regional Totals). Applying "Next Generation" CO_2-EOR in the Permian Basin would provide significant additional oil recovery and CO_2 storage capacity, Table VI-6.5:

- Economic oil recovery would be 14.6 billion barrels with "Next Generation" CO_2-EOR technology compared to 6.4 billion barrels with State of Art technology.
- Economic CO_2 demand (and storage capacity) would be 4,750 million metric tons gross and 3,210 million metric tons net, with "Next Generation" technology compared to 2,690 million metric tons gross and 1,150 million metric tons net with State of Art technology.

Table VI-6.5. Summary Table of Comparison of State of Art and "Next Generation" CO_2-EOR Technology: Permian Basin Regional Totals**

		State of Art	"Next Generation"
Oil Recovery (Billion Barrels)			
	▪ Technical	13.6	24.0
	▪ Economic	6.4	14.6
CO_2 Demand (Million Metric Tons)			
	▪ Technical	6,070	8,620
	▪ Economic		
	– Gross*	2,690	4,750
	– Net	1,150	3,210

* Includes 1,540 million metric tons of CO_2 demand expected to be provided by natural sources and gas processing plants.
**Includes 2.2 billion barrels already produced or proven with miscible CO_2-EOR technology.

In addition, with “Next Generation” CO_2-EOR technology, the massive oil resource in the ROZs of the Permian Basin below 56 existing oil fields became feasible to be pursued, providing 11.9 billion barrels of technically recoverable resource and 4.8 million metric tons of CO_2 demand and storage capacity.

Expanding the understanding of ROZs beneath existing oil fields (reflected in the above resource number) to regionally extensive ROZ “fairways” would significantly increase the oil resource available from residual oil zones. This represents a major opportunity for “Next Generation” CO_2-EOR R&D.

7. *Rockies*

a. Background. The pursuit of new oil plays as well as the liquids-rich shale plays such as the Niobrara and Mancos shales have increased the rate of oil production in this region to 103 million barrels per year (280,000 barrels per day) in 2009 (Table VI-7.1).

Table VI-7.1. Oil Production from the Rockies (MM Bbls/Yr)

Year	Colorado*	Utah	Wyoming	TOTAL
2000	19	16	61	96
2001	18	15	57	90
2002	19	14	55	88
2003	22	13	52	87
2004	23	15	52	90
2005	24	17	52	93
2006	24	18	53	95
2007	24	20	54	98
2008	25	22	53	100
2009	29	23	51	103

*Includes New Mexico West. Source: EIA Crude Oil Production by State (March 2011).

b. Summary of Results. Advanced Resources' Big Oil Fields Database for the Rockies contains 142 oil reservoirs that screen favorably for miscible CO_2-EOR plus 4 oil reservoirs that screen favorably for near miscible CO_2-EOR. These 146 reservoirs contain 22.5 billion barrels of OOIP out of a database of 172 reservoirs with 24.7 billion of OOIP.

c. Miscible CO_2-EOR.

(1). Database. The data for the 142 the Rockies oil reservoirs favorable for miscible CO_2-EOR are as follows:

Original Oil In-Place	21.9 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	7.1 billion barrels
Primary/Secondary Oil Recovery Efficiency	33%
Remaining Oil In-Place	14.7 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 142 oil reservoirs offers the potential for technically recovering 5.8 billion barrels of the remaining oil in-place, equal to 26% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 120 of the 142 oil reservoirs provide at least a 20% rate of return (before tax) and thus are deemed to be economically feasible. The economically feasible oil recovery is 4.7 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 142 Rockies oil fields technically favorable for miscible CO_2-EOR is 1,650 million metric tons (31 Tcf). The volume of purchased CO_2 for the 120 Rockies oil reservoirs economically favorable for miscible CO_2-EOR is 1,270 million metric tons (24 Tcf).

(5) Summary Table. Table VI-7.2 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of miscible "Next Generation" CO_2-EOR in Rockies.

Table VI-7.2. Rockies Oil Recovery and CO_2 Demand from Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand** (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	5.8	4.7	1,650	1,270
2. Regional Totals	9.6	4.7	2,750	1,270

*Database totals extrapolated to regional totals using a dividing factor of 0.6.
** Includes 330 million metric tons of CO_2 demand expected to be provided by natural sources and gas processing plants.

d. Near Miscible CO_2-EOR.

(1). Database. The data for the Rockies oil reservoirs favorable for near miscible CO_2-EOR are as follows:

Original Oil In-Place	0.6 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	0.2 billion barrels
Primary/Secondary Oil Recovery Efficiency	24%
Remaining Oil In-Place	0.5 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 4 oil reservoirs offers the potential for technically recovering less than a tenth of one billion barrels of the remaining oil in-place, equal to 4% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2, none of the oil reservoirs provide at least a 20% rate of return (before tax) and thus none are economically feasible.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 4 Rockies oil fields technically favorable for near miscible CO_2-EOR is 30 million metric tons (<1 Tcf).

(5) Summary Table. Table VI-7.3 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of near miscible "Next Generation" CO_2-EOR in the Rockies.

Table VI-7.3. Rockies Oil Recovery and CO_2 Demand from Near Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	<1	-	30	-
2. Regional Totals	<1	-	40	-

*Database totals extrapolated to regional totals using a dividing factor of 0.6.

e. Miscible and Near Miscible CO_2-EOR. Table VI-7.4 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of "Next Generation" CO_2-EOR in Rockies.

Table VI-7.4. Rockies Oil Recovery and CO_2 Demand from "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand** (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	5.8	4.7	1,670	1,270
2. Regional Totals	9.7	4.7	2,790	1,270

*Database totals extrapolated to regional totals using a dividing factor of 0.6.
** Includes 230 million metric tons of CO2 demand expected to be provided by natural sources and gas processing plants.

f. Comparison of State of Art and "Next Generation" CO_2-EOR Technology. Applying "Next Generation" CO_2-EOR in the Rockies would provide valuable additional oil recovery and CO_2 storage (Table VI-7.5).

- Economic oil recovery would be 4.7 billion barrels with "Next Generation" technology compared to 1.9 billion barrels with State of Art technology.
- Economic CO_2 demand (and storage capacity) would be 1,270 million metric tons with "Next Generation" technology compared to 710 million metric tons (gross) with State of Art technology.

Table VI-7.5. Summary Table of Comparison of State of Art and "Next Generation" CO_2-EOR Technology: Rockies (Regional Totals)

		State of Art	"Next Generation"
Oil Recovery (Billion Barrels)**			
	▪ Technical	4.5	9.7
	▪ Economic	1.9	4.7
CO_2 Demand (Million Metric Tons)			
	▪ Technical	1,930	2,790
	▪ Economic		
	– Gross*	710	1,270
	– Net	480	1,040

* Includes 230 million metric tons of CO_2 demand expected to be provided by natural sources and gas processing plants.
**Includes 0.3 billion barrels already produced or proven with miscible CO_2-EOR technology.

In addition, with "Next Generation" CO_2-EOR technology, the residual oil zone (ROZ) resources in the Big Horn would provide 1.1 billion barrels of technically recoverable resources below 13 existing oil fields and would provide 0.4 million metric tons of CO_2 demand and storage capacity.

8. Southeast Gulf Coast

a. Background. The recent introduction of CO_2-EOR in Mississippi and Louisiana has helped stem the decline in oil production in this area. Oil production from the Southeast Gulf Coast was 100 million barrels (270,000 barrels per day) in 2009 (Table VI-8.1).

Table VI-8.1. Oil Production from the Southeast Gulf Coast (MM Bbls/Yr)

Year	Louisiana	Mississippi	Alabama/Florida	TOTAL
2000	105	20	15	140
2001	105	20	14	139
2002	93	18	12	123
2003	90	17	11	118
2004	83	17	10	110
2005	75	18	10	103
2006	74	17	10	101
2007	77	20	9	106
2008	73	22	10	105
2009	69	23	8	100

Source: EIA Crude Oil Production by State (March 2011).

b. Summary of Results. Advanced Resources' Big Oil Fields Database for the Southeast Gulf Coast contains 204 oil reservoirs that screen favorably for miscible CO_2-EOR plus 5 oil reservoirs that screen favorably for near miscible CO_2-EOR. These 209 reservoirs contain 23.8 billion barrels of OOIP out of a database of 298 reservoirs with 26.4 billion of OOIP.

c. Miscible CO_2-EOR.

(1). Database. The data for the 204 Southeast Gulf Coast oil reservoirs favorable for miscible CO_2-EOR are as follows:

Original Oil In-Place	23.3 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	9.1 billion barrels
Primary/Secondary Oil Recovery Efficiency	39%
Remaining Oil In-Place	14.2 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 204 oil reservoirs offers the potential for technically recovering 6.0 billion barrels of the remaining oil in-place, equal to 26 % of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 146 of the 204 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. The economically feasible oil recovery is 4.8 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 204 Southeast Gulf Coast oil fields technically favorable for miscible CO_2-EOR is 2,010 million metric tons (38 Tcf). The volume of purchased CO_2 for the 146 Southeast Gulf Coast oil reservoirs economically favorable for miscible CO_2-EOR is 1,440 million metric tons (27 Tcf).

Subtracting out the 130 million metric tons (3 Tcf) of CO_2 expected to be delivered to the Gulf Coast from natural sources (at 0.3 Bcfd for 30 years), still leaves a near- to mid-term market for purchase (and storage) of anthropogenic CO_2 of 1,310 million metric tons (24 Tcf).

(5) Summary Table. Table VI-8.2 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of miscible Next Generation CO_2-EOR in Southeast Gulf Coast for the database and extrapolated to regional totals.

Table VI-8.2. Southeast Gulf Coast Oil Recovery and CO_2 Demand from Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand** (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	6.0	4.8	2,010	1,440
2. Regional Totals	10.1	4.8	3,350	1,440

*Database totals extrapolated to regional totals using a dividing factor of 0.60.
** Includes 130 million metric tons of CO_2 demand expected to be provided by natural sources and gas processing plants.

d. Near Miscible CO_2-EOR.

(1). Database. The data for the 5 Southeast Gulf Coast oil reservoirs favorable for near miscible CO_2-EOR are as follows:

Original Oil In-Place	0.54 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	0.16 billion barrels
Primary/Secondary Oil Recovery Efficiency	30%
Remaining Oil In-Place	0.38 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 5 oil reservoirs offers the potential for technically recovering less than a tenth of one billion barrels of the remaining oil in-place, equal to 7% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), none of the oil reservoirs provide at least a 20% rate of return (before tax) and thus none are economically feasible.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 5 Southeast Gulf Coast oil fields technically favorable for near miscible CO_2-EOR is 30 million metric tons (1 Tcf).

(5) Summary Table. Table VI-8.3 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of near miscible "Next Generation" CO_2-EOR in Southeast Gulf Coast.

Table VI-8.3. Southeast Gulf Coast Oil Recovery and CO_2 Demand from Near Miscible "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	<0.1	-	30	-
2. Regional Totals	0.1	-	40	-

*Database totals extrapolated to regional totals using a dividing factor of 0.6.

e. Miscible and Near Miscible CO_2-EOR. Table VI-8.4 provides a summary of the oil recovery and CO_2 demand storage potential available from the application of "Next Generation" CO_2-EOR in Southeast Gulf Coast.

Table VI-8.4. Southeast Gulf Coast Oil Recovery and CO_2 Demand from "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand** (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	6.1	4.8	2,040	1,440
2. Regional Totals	10.1	4.8	3,390	1,440

*Database totals extrapolated to regional totals using a dividing factor of 0.60.
**Includes 130 million metric tons of CO_2 demand provided by natural sources and gas processing plants.

f. Comparison of State of Art and "Next Generation" CO_2-EOR Technology. Applying "Next Generation" CO_2-EOR in the Southeast Gulf Coast would provide valuable additional oil recovery and CO_2 storage (Table VI-8.5).

- Economic oil recovery would be 4.8 billion barrels with "Next Generation" technology compared to 0.9 billion barrels with State of Art technology.
- Economic CO_2 demand (and storage capacity) would be 1,440 million metric tons (gross) with "Next Generation" technology compared to 290 million metric tons (gross) with State of Art technology.

Table VI-8.5. Summary Table of Comparison of State of Art and "Next Generation" CO_2-EOR Technology: Southeast Gulf Coast (Regional Totals)

		State of Art	Next Generation
Oil Recovery (Billion Barrels)			
	▪ Technical	5.4	10.1
	▪ Economic	0.9	4.8
CO_2 Demand (Million Metric Tons)			
	▪ Technical	2,590	3,390
	▪ Economic		
	– Gross*	290	1,440
	– Net	160	1,310

* Includes 130 million metric tons of CO_2 demand expected to be provided by natural sources and gas processing plants.

9. *Williston Basin*

a. Background. With the discovery and aggressive development of the Bakken Shale, oil production from the Williston Basin has more than doubled during this decade, reaching 109 million barrels per year (300,000 barrels per day), Table VI-9.1.

Table VI-9.1. Oil Production from the Williston Basin (MM Bbls/Yr)

Year	N/S Dakota	Montana	TOTAL
2000	34	15	49
2001	33	16	49
2002	32	17	49
2003	31	19	50
2004	33	25	58
2005	37	33	70
2006	41	36	77
2007	47	35	82
2008	64	32	96
2009	81	28	109

Source: EIA Crude Oil Production by State (March 2011).

b. Summary of Results. Advanced Resources' Big Oil Fields Database for the Williston Basin contains 86 oil reservoirs that screen favorably for miscible CO_2-EOR. These 86 reservoirs contain 9.3 billion barrels of OOIP out of a database of 95 reservoirs with 9.4 billion of OOIP.

c. Miscible CO_2-EOR.

(1). Database. The data for the 86 Williston Basin oil reservoirs favorable for miscible CO_2-EOR are as follows:

Original Oil In-Place	9.3 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	2.6 billion barrels
Primary/Secondary Oil Recovery Efficiency	28 %
Remaining Oil In-Place	6.7 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 86 oil reservoirs offers the potential for technically recovering 2.8 billion barrels of the remaining oil in-place, equal to 30% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 40 of the 86 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. The economically feasible oil recovery is 1.3 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 demand for the 86 Williston Basin oil fields technically favorable for miscible CO_2-EOR is 820 million metric tons (15 Tcf). The volume of purchased CO_2 demand for the 40 Williston Basin oil reservoirs economically favorable for miscible CO_2-EOR is 360 million metric tons (7 Tcf).

(5). Summary. Table VI-9.2 provides a summary of the oil recovery and CO_2 demand storage potential from the application of "Next Generation" CO_2-EOR in Williston Basin.

Table VI-9.2. Williston Basin Oil Recovery and CO_2 Demand from "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	2.8	1.3	820	360
2. Regional Totals	4.0	1.3	1,150	360

*Database totals extrapolated to regional totals using a dividing factor of 0.71.

d. Near Miscible CO_2-EOR. At this time, no oil reservoirs in the Williston Basin screen favorably for near miscible CO_2-EOR.

e. Comparison of State of Art and "Next Generation" CO_2-EOR Technology. Applying "Next Generation" CO_2-EOR in the Williston Basin would provide valuable additional oil recovery and CO_2 storage (Table VI-9.3).

- Economic oil recovery would be 1.3 billion barrels with "Next Generation" technology compared to 0.3 billion barrels with State of Art technology.
- Economic CO_2 demand (and storage capacity) would be 360 million metric tons with "Next Generation" technology compared to 130 million metric tons with State of Art technology.

Table VI-9.3. Summary Table of Comparison of State of Art and "Next Generation" CO_2-EOR Technology: Williston Basin (Regional Totals)

		State of Art	"Next Generation"
Oil Recovery (Billion Barrels)			
	▪ Technical	2.1	4.0
	▪ Economic	0.3	1.3
CO_2 Demand (Million Metric Tons)			
	▪ Technical	820	1,150
	▪ Economic	130	360

In addition, with "Next Generation" CO_2-EOR technology, the residual oil zone (ROZ) resources below 20 existing oil fields in the Williston Basin would provide 3.3 billion barrels of technically recoverable resources and would provide 1.3 million metric tons of CO_2 demand and storage capacity.

10. Alaska

a. Background. From a peak of 738 million barrels (2 million barrels per day) in 1988, oil production from Alaska's North Slope and Cook Inlets declined steadily -- 355 million barrels (1 million barrels per day) in 2000 and has 219 million barrels (600,000 barrels per day) in 2010 (Table VI-10.1).

Table VI-10.1. Oil Production from Alaska (MM Bbls/Yr)

Year	TOTAL
2000	355
2001	351
2002	359
2003	356
2004	332
2005	315
2006	270
2007	266
2008	250
2009	236
2010	219

Source: EIA Crude Oil Production by State (March 2011).

b. Reservoirs Favorable for CO_2-EOR. Advanced Resources' Big Oil Fields Database for Alaska contains 36 oil reservoirs that screen favorably for miscible CO_2-EOR. These 36 reservoirs contain 50.1 billion barrels of OOIP out of a data base of 43 reservoirs with 50.7 billion of OOIP.

c. Miscible CO_2-EOR.

(1). Database. The data for the 36 Alaska oil reservoirs favorable for miscible CO_2-EOR are as follows:

Original Oil In-Place	50.1 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	21.7 billion barrels
Primary/Secondary Oil Recovery Efficiency*	43%
Remaining Oil In-Place	28.4 billion barrels

*Includes oil recovery from hydrocarbon miscible EOR.

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 36 oil reservoirs offers the potential for technically recovering 8.7 billion barrels of the remaining oil in-place, equal to 17% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 19 of the 36 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. The economically feasible oil recovery is 5.7 billion barrels

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 36 Alaska oil fields technically favorable for miscible CO_2-EOR is 4,070 million metric tons (77 Tcf). The volume of purchased CO_2 for the 19 Alaska oil reservoirs economically favorable for miscible CO_2-EOR is 2,330 million metric tons (44 Tcf).

(5). Summary Table . Table VI-10.2 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of miscible "Next Generation" CO_2-EOR in Alaska.

Table VI-10.2. Alaska Oil Recovery and CO_2 Demand from "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	**Economic**	**Technical***	**Economic**
1. Database Totals	8.7	5.7	4,070	2,330
2. Regional Totals	8.8	5.7	4,110	2,330

*Database totals extrapolated to regional totals using a dividing factor of 0.99.

d. Near Miscible CO_2-EOR. At this time, no oil reservoirs in Alaska screened favorably for near miscible CO_2-EOR.

e. Comparison of State of Art and "Next Generation" CO_2-EOR Technology. Applying "Next Generation" CO_2-EOR in Alaska would provide valuable additional oil recovery and CO_2 storage (Table VI-10.3).

- Economic oil recovery would be 5.7 billion barrels with "Next Generation" technology compared to 2.6 billion barrels with State of Art technology.

- Economic CO_2 demand (and storage capacity) would be 2,330 million metric tons with "Next Generation" technology compared to 1,490 million metric tons with State of Art technology.

Table VI-10.3. Summary Table of Comparison of State of Art and "Next Generation" CO_2-EOR Technology: Alaska (Regional Totals)

		State of Art	"Next Generation"
Oil Recovery (Billion Barrels)			
	▪ Technical	5.8	8.8
	▪ Economic	2.6	5.7
CO_2 Demand (Million Metric Tons)			
	▪ Technical	3,320	4,110
	▪ Economic	1,490	2,330

11. Offshore Gulf of Mexico

a. Background. With the onset of new oil fields from deep waters, oil production from the Federal Offshore Gulf of Mexico and the state waters rebounded to 576 million barrels in 2009 (1,580,000 barrels per day) (Table VI-11.1).

Table VI-11.1. Oil Production from the Offshore Gulf of Mexico (MM Bbls/Yr)

Year	Federal Offshore	Louisiana State Offshore	Texas State Offshore	TOTAL
2000	523	13	1	537
2001	560	13	1	574
2002	568	11	1	580
2003	569	11	1	581
2004	532	10	1	543
2005	468	8	1	477
2006	474	8	*	482
2007	466	8	1	475
2008	422	6	1	429
2009	569	6	1	576

*Less than 0.5 million barrels. Source: EIA Crude Oil Production by State (March 2011).

b. Summary of Results. Advanced Resources' Big Oil Fields Database for the Offshore Gulf of Mexico contains 646 oil reservoirs (in 146 fields) that screen favorably for miscible CO_2-EOR. These 646 reservoirs contain 29.5 billion barrels of OOIP.

c. Miscible CO_2-EOR.

(1). Database. The data for the 646 Offshore Gulf of Mexico oil reservoirs favorable for miscible CO_2-EOR are as follows:

Original Oil In-Place	29.5 billion barrels
Expected Ultimate Primary/Secondary Oil Recovery	12.1 billion barrels
Primary/Secondary Oil Recovery Efficiency	41 %
Remaining Oil In-Place	17.4 billion barrels

(2). Technically Recoverable. "Next Generation" CO_2-EOR technology applied to these 646 oil reservoirs offers the potential for technically recovering 6.0 billion barrels of the remaining oil in-place, equal to 20% of OOIP.

(3). Economically Recoverable. Using an oil price of $85 per barrel (WTI) and $40 per metric ton of CO_2 (delivered at pressure to the basin), 123 oil reservoirs provide at least a 20% rate of return (before tax) and thus are economically feasible. The economically feasible oil recovery is 0.9 billion barrels.

(4). Purchase and Storage of CO_2. The volume of purchased CO_2 for the 146 Offshore Gulf of Mexico oil fields (646 reservoirs) technically favorable for miscible CO_2-EOR is 1,770 million metric tons (33 Tcf). The volume of purchased CO_2 for the 123 Offshore Gulf of Mexico oil reservoirs economically favorable for miscible CO_2-EOR is 260 million metric tons (4 Tcf).

(5). Summary Table. Table VI-11.2 provides a summary of the oil recovery and CO_2 demand and storage potential from the application of "Next Generation" CO_2-EOR in Offshore Gulf of Mexico.

Table VI-11.2. Offshore Gulf of Mexico Oil Recovery and CO_2 Demand from "Next Generation" CO_2-EOR

	Oil Recovery (Billion Barrels)		CO_2 Demand (Million Metric Tons)	
	Technical*	Economic	Technical*	Economic
1. Database Totals	6.0	0.9	1,770	260
2. Regional Totals	6.0	0.9	1,770	260

*Regional totals equal data base totals.

d. Near Miscible CO_2-EOR. At this time, no oil reservoirs in the Offshore Gulf of Mexico screened favorably for near miscible CO_2-EOR.

e. Comparison of State of Art and "Next Generation" CO_2-EOR Technology. Given the barriers, complexities and economic challenges of initiating CO_2-EOR in the Offshore Gulf of Mexico oil fields, this region, only feasible with "Next Generation" technology.

VII. OVERVIEW OF METHODOLOGY

A. Six Step Methodology

A six part methodology was used to assess the CO_2 storage potential of applying "Next Generation" CO_2-EOR technology to domestic oil reservoirs. The six steps were: (1) assembling and updating the Major Oil Reservoirs Database containing over 6,300 large domestic oil reservoirs; (2) calculating the minimum miscibility pressure for applying CO_2 -EOR; (3) using minimum miscibility pressure and other criteria to screen reservoirs favorable for miscible and near miscible CO_2-EOR; (4) calculating oil recovery from applying "Next Generation" CO_2-EOR technology; and (5) applying the updated cost and economic model. Step 6 was to incorporate the prior work conducted by Advanced Resources and Melzer Consulting on residual oil zones (ROZs) into this study and report.

B. Cost Model

The cost model includes costs for: (1) drilling new wells or reworking existing wells; (2) providing surface equipment for new wells; (3) installing the CO_2 recycle plant; (4) constructing a CO_2 spur-line from the main CO_2 trunkline to the oil field; and (5) other capital investment costs. The cost model also accounts for normal well operation and maintenance (O&M), for lifting costs of the produced fluids, and for costs of capturing, separating and reinjecting the produced CO_2.

C. Economic Model

The economic model used by the study is an industry standard cash flow model run on either a pattern or a field-wide basis. The key inputs and assumptions of the economic model include the following: (1) Oil Price - - $85 per barrel (WTI reference price); (2) CO_2 Purchase Costs - - $40 per metric ton (delivered at pressure to the oil field); (3) Financial Hurdle Rate - - 20% ROR (before tax); (4) Royalties - - 17.5%; (5) State Severance/Ad Valorem Taxes - - State specific; (6) CO_2 Reinjection Cost ($/Mcf) - - 1% of oil price ($/barrel) (for compression and treatment); and (7) CAPEX and OPEX - - state and depth specific.

D. Regional Scaling Factors

A series of scaling factors are used to extrapolate the technical oil recovery from the sample of oil fields in the Big Oil Fields Database to regional totals, as shown in Chapter 6 for each region. For two of the regions, Alaska and the Offshore Gulf of Mexico, the Big Oil Fields Database contains essentially all of the past oil production and proved reserves for these two regions. For other regions, the scaling factors range from 59% to 99%.

The scaling factor for technically recoverable oil for each region is based on the volume of oil production and proved reserves represented by the oil fields in the data base to total oil production and proved reserves reported for the region.

No scaling factors are used for extrapolating economically recoverable oil from the oil fields in the data base to regional totals. The economic results from the large oil fields in the data base, which tend to have more favorable economics due to resource size and scale, may not be representative of the economics of the thousands of smaller oil fields in a given region.

E. Additional "Next Generation" Model Features

The study incorporated the following additional features into this version of the "Next Generation" CO_2-EOR Model:

- The analysis assumes that the thinner, edge areas of the oil field, accounting for 20% of and reservoir area and 10% of the OOIP, will not be feasible for application of CO_2-EOR.

- The oil recovery model assumes that the residual oil left in the pore space after CO_2 injection (S_{orm}) is 8%. This compares to the previous analysis that used a more complex algorithm that related the S_{orm} to volumes of CO_2 injected.

- The model currently uses tapered WAG ratios starting with an initial large slug of CO_2 before introducing water for mobility control. The previous analysis used a consistent ("simple") WAG ratio. An economic truncation algorithm (comparing annual revenues with annual costs) halts project operation and CO_2 injection once annual cash flow becomes negative.

- The analysis assumes that 25% of the injected CO_2 is dissolved in the reservoirs water or is lost outside the pattern area and thus is not available as recycled CO_2 for meeting total CO_2 injection needs.

Additional detail on the "Next Generation" CO_2-EOR study methodology is provided in Appendix A.

APPENDIX A
Discussion of Study Methodology

STUDY METHODOLOGY

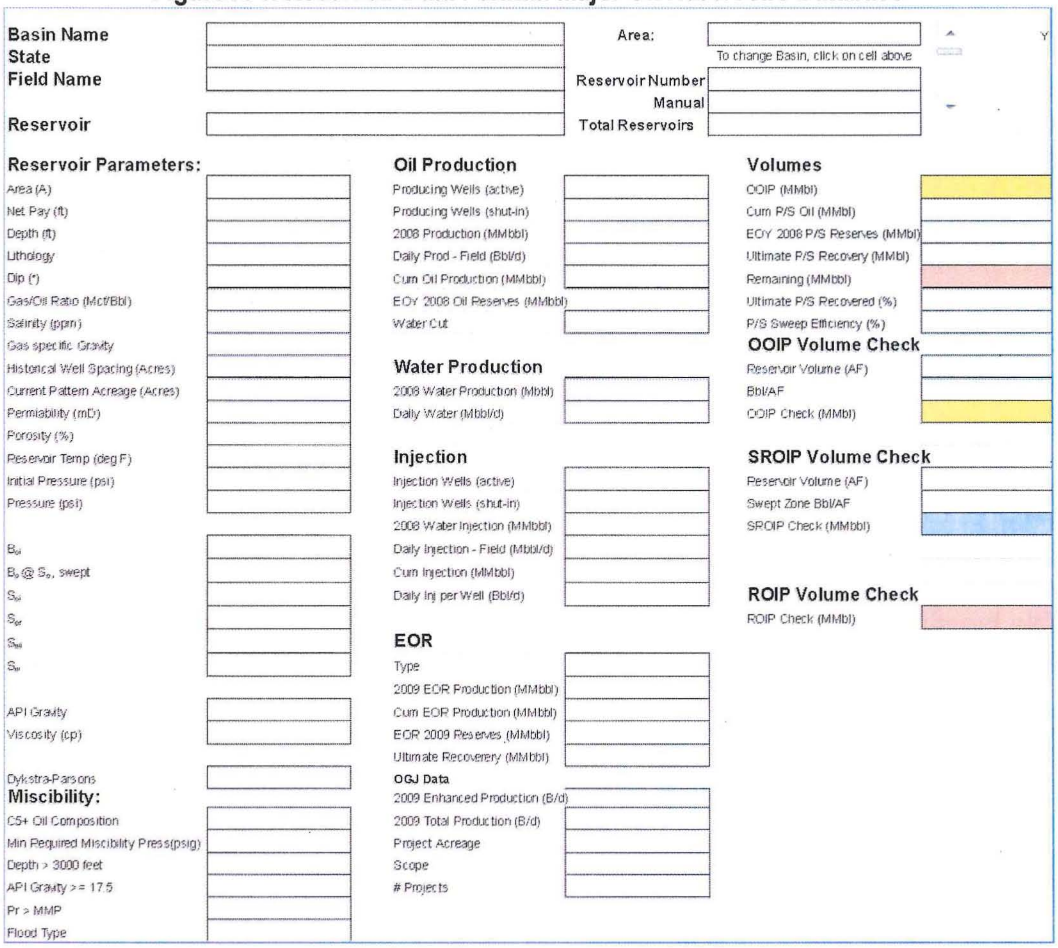
A five part methodology was used to assess the CO_2 storage and EOR potential of domestic oil reservoirs. The six steps were: (1) assembling and updating the Major Oil Reservoirs Database; (2) calculating the minimum miscibility pressure for applying CO_2 -EOR; (3) using minimum miscibility pressure and other criteria to screen reservoirs favorable for CO_2-EOR; (4) calculating oil recovery from applying "Next Generation" CO_2-EOR technology; and (5) applying the updated cost and economic model.

A. Assembling The Major Oil Reservoirs Database

Overall, the Major Oil Reservoirs Database contains over 6,300 reservoirs, accounting for 75% of the oil expected to be ultimately produced in the U.S. by primary and secondary oil recovery processes. Figure A-1 illustrates a portion of the reservoir data included in the Major Oil Reservoirs Database.

Considerable effort has been invested to construct an up-to-date, volumetrically consistent database that contained all of the essential data, formats and interfaces to enable the study to: (1) develop an accurate estimate of the size of the original and remaining oil in-place; (2) reliably screen the reservoirs as to their amenability for miscible and immiscible CO_2-EOR; and, (3) provide the *CO_2-PROPHET* Model the essential input data for calculating CO_2 injection requirements and oil recovery.

Figure A-1. Reservoir Data Format: Major Oil Reservoirs Database



Basin Name
State
Field Name
Reservoir

Area:
To change Basin, click on cell above
Reservoir Number
Manual
Total Reservoirs

Reservoir Parameters:
Area (A)
Net Pay (ft)
Depth (ft)
Lithology
Dip (°)
Gas/Oil Ratio (Mcf/Bbl)
Salinity (ppm)
Gas specific Gravity
Historical Well Spacing (Acres)
Current Pattern Acreage (Acres)
Permiability (mD)
Porosity (%)
Reservoir Temp (deg F)
Initial Pressure (psi)
Pressure (psi)

B_{oi}
B_o @ S_o, swept
S_{oi}
S_{or}
S_{wi}
S_w

API Gravity
Viscosity (cp)

Dykstra-Parsons

Miscibility:
C5+ Oil Composition
Min Required Miscibility Press(psig)
Depth > 3000 feet
API Gravity >= 17.5
Pr > MMP
Flood Type

Oil Production
Producing Wells (active)
Producing Wells (shut-in)
2008 Production (MMbbl)
Daily Prod - Field (Bbl/d)
Cum Oil Production (MMbbl)
EOY 2008 Oil Reserves (MMbbl)
Water Cut

Water Production
2008 Water Production (Mbbl)
Daily Water (Mbbl/d)

Injection
Injection Wells (active)
Injection Wells (shut-in)
2008 Water Injection (MMbbl)
Daily Injection - Field (Mbbl/d)
Cum Injection (MMbbl)
Daily Inj per Well (Bbl/d)

EOR
Type
2009 EOR Production (MMbbl)
Cum EOR Production (MMbbl)
EOR 2009 Reserves (MMbbl)
Ultimate Recoverery (MMbbl)

OGJ Data
2009 Enhanced Production (B/d)
2009 Total Production (B/d)
Project Acreage
Scope
Projects

Volumes
OOIP (MMbl)
Cum P/S Oil (MMbl)
EOY 2008 P/S Reserves (MMbl)
Ultimate P/S Recovery (MMbl)
Remaining (MMbbl)
Ultimate P/S Recovered (%)
P/S Sweep Efficiency (%)

OOIP Volume Check
Reservoir Volume (AF)
Bbl/AF
OOIP Check (MMbl)

SROIP Volume Check
Reservoir Volume (AF)
Swept Zone Bbl/AF
SROIP Check (MMbbl)

ROIP Volume Check
ROIP Check (MMbl)

B. Calculating Minimum Miscibility Pressure

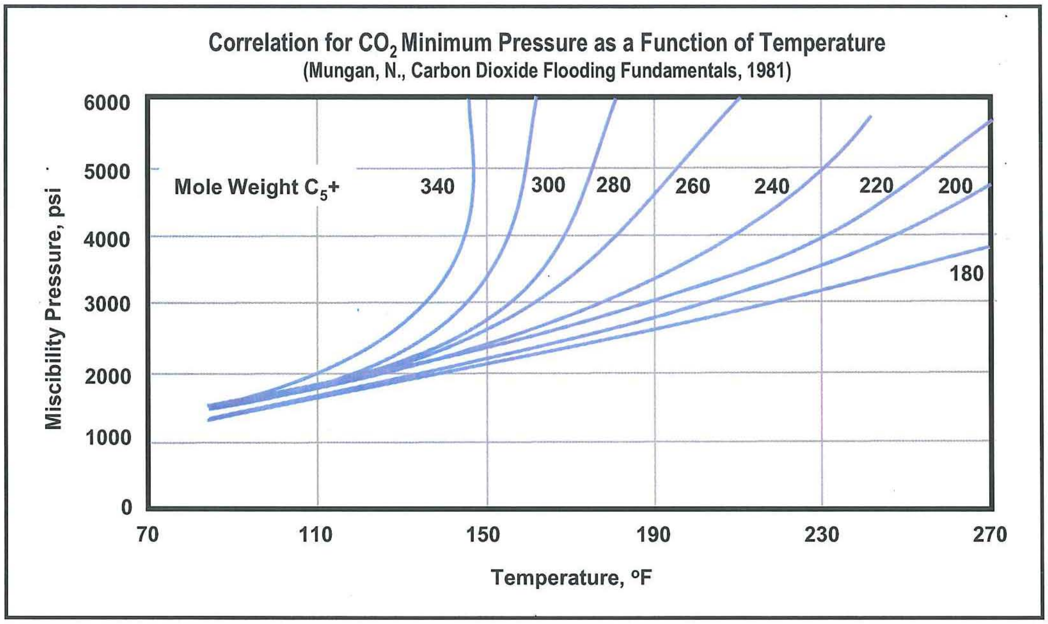
The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and oil composition, is to determine whether the reservoir would hold sufficient pressure to attain miscibility. To determine the minimum miscibility pressure (MMP) for any given reservoir, the study used the Cronquist correlation. This formulation determines MMP based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil, as set forth below:

$$MMP = 15.988 * T^{(0.744206+0.0011038*MW\ C5+)}$$

Where: T is Temperature in °F, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

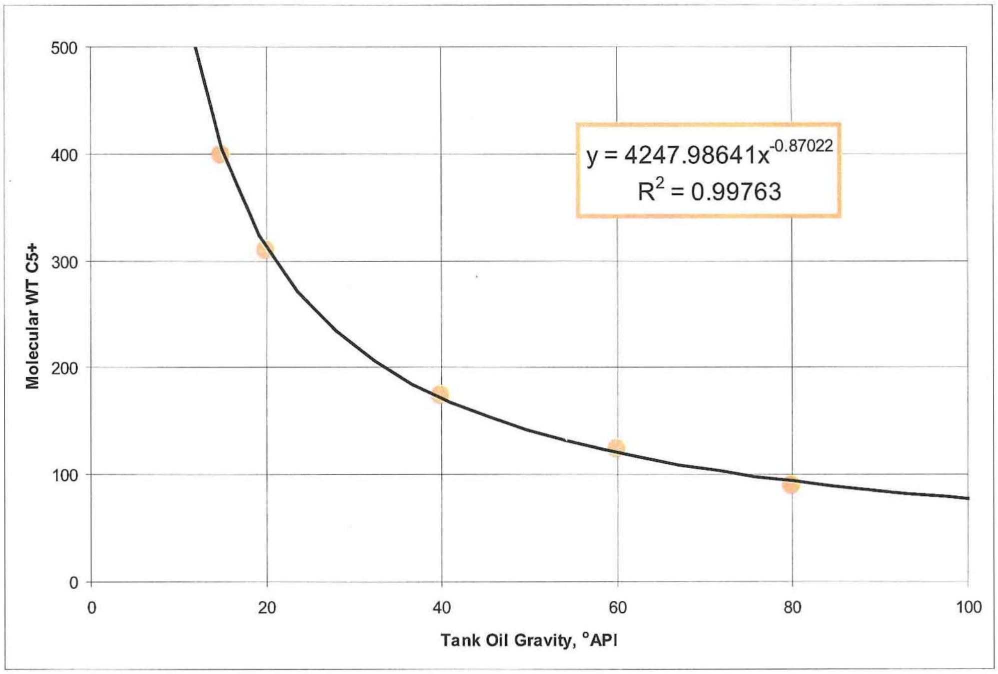
A similar approach to estimating minimum miscibility pressure, prepared by Mungan (1981), is shown on Figure A-2.

Figure A-2. Estimating CO_2 Minimum Miscibility Pressure



The temperature of the reservoir was taken from the database or estimated from the thermal gradient in the basin. The molecular weight of the pentanes and heavier fraction of the oil was obtained from the database or was estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure A-3.

Figure A-3. Correlation of MW C5+ to Tank Oil Gravity



C. Screening Reservoirs for CO_2-EOR

The preliminary screening steps involved selecting the deeper oil reservoirs that had sufficiently high oil gravity. A minimum reservoir depth of 2,500 to 3,000 feet, at the mid-point of the reservoir, was used to ensure the reservoir could accommodate high pressure CO_2 injection. A minimum oil gravity of 17.5 °API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection.

The next step was comparing the minimum miscibility pressure (MMP) to the maximum allowable pressure. The maximum pressure was determined using a pressure gradient of 0.6 to 0.7 psi/foot, depending on the region. If the minimum miscibility pressure was below the maximum injection pressure, the reservoir was classified as a miscible flood candidate. Oil reservoirs that did not screen positively for miscible CO_2-EOR were selected for consideration by near miscible CO_2-EOR.

D. Calculating Oil Recovery

The study utilized *CO_2-PROPHET* to calculate incremental oil produced using "Next Generation" CO_2-EOR technology.

- *CO_2-PROPHET* generates streamlines for fluid flow between injection and production wells, and
- The model performs oil displacement and recovery calculations along the established streamlines. (A finite difference routine is used for oil displacement calculations.)

Even with these features, it is important to note the *CO_2-PROPHET* is still primarily a "screening-type" model, and lacks some of the key features, such as gravity override and compositional changes to fluid phases, available in more sophisticated reservoir simulators. More detailed assessments of CO_2-EOR would need to use a compositional, 3D reservoir simulator.

E. Assembling The Cost and Economics Models

A detailed, up-to-date CO_2-EOR Cost Model was developed for the study. The model includes costs for: (1) drilling new wells or reworking existing wells; (2) providing surface equipment for new wells; (3) installing the CO_2 recycle plant; (4) constructing a CO_2 spur-line from the main CO_2 trunkline to the oil field; and (5) other costs.

The cost model also accounts for normal well operation and maintenance (O&M), for lifting costs of the produced fluids, and for costs of capturing, separating and reinjecting the produced CO_2.

The economic model used by the study is an industry standard cash flow model that can be run on either a pattern or a field-wide basis. The economic model accounts for royalties, severance and ad valorem taxes, as well as any oil gravity and market location discounts (or premiums) from the "marker" oil price.

The key inputs and assumptions of the economic model include the following:

- Oil Price - - $85 per barrel (WTI reference price). The oil price selected for the analysis is consistent with EIA's Annual Energy Outlook oil price for years 2012 and 2013.
- CO_2 Purchase Price - - $40 per metric ton (delivered at pressure to the oil field). The CO_2 purchase price selected is consistent with historical ratios relating to CO_2 purchase to oil price using a value of 2.5% (with a range of 2% to 3%) of the oil price to calculate the CO_2 purchase price in $/Mcf. For example at an $85 per barrel oil price, the CO_2 purchase price would be $2.12/Mcf equal to about $40 per metric ton.
- Financial Hurdle Rate - - 20% ROR (before tax)
- Royalties - - 17.5%
- State Severance/Ad Valorem Taxes - - State specific
- CO_2 Reinjection Cost - - 1% of oil price (for compression and treatment)
- CAPEX and OPEX - - State and depth specific.

G. Other Considerations

Based on discussions with operators, the study incorporated the following additional features into this version of the "Next Generation" CO_2-EOR Model:

- The analysis assumes that the thinner, edge areas of the oil field, accounting for 20% of the field and reservoir area and 10% of the OOIP, will not be feasible for application of CO_2-EOR.
- The oil recovery model assumes that the residual oil left in the pore space after CO_2 injection is 8%.
- The quantity of CO_2 injected is up to 1.5 HCPV. The tapered WAG ratios includes an initial large slug of CO_2 plus water for mobility control.
- An economic truncation algorithm (comparing annual revenues with annual costs) halts project operation and CO_2 injection once annual cash flow becomes negative.
- The analysis assumes that 25% of the injected CO_2 is dissolved in water or is lost outside the pattern area.

APPENDIX B
A Summary of the Meetings with Industry Practitioners

Background

A series of "field" visits and meetings were held with industry experts active in applying CO_2-EOR technology. The purpose of the visits and meetings were to: (1) obtain industry feedback on the methodology and results of the NETL/ARI studies of CO_2-EOR; and (2) to discuss observations and recommendations for conducting an updated assessment of "Next Generation" CO_2-EOR and CO_2 storage.

Three specific industry review meetings were held in September 2010 involving Don Remson of NETL, Vello Kuuskraa, Robert Ferguson and Tyler Van Leeuwen of Advanced Resources International and Bob Blaylock of BAH.

- The first meeting was on September 9, 2010 in Houston, Texas with Kinder Morgan. This meeting involved two Kinder Morgan staff - - Lanny Schoeling, Vice President, Engineering & Technical Development and Steve Pontious, Staff Engineer.
- The second meeting was during the afternoon of September 9, 2010 in Houston, Texas with Hess Corporation. This meeting involved four staff - - Manuel De Jesus Valle, Geological Advisor, Americas Onshore Subsurface; Ed De Zabala, Senior Reservoir Engineering Advisor, EOR Exploration and Production Technology; Alvaro Grijalba, Subsurface Team Lead, Americas Technical – Permian; and Paul Carmody, Facilities Engineering Advisor, Americas Production Excellence.
- The third meeting was on September 16, 2010 in Midland, Texas with a number of industry experts from eight companies. The meeting involved:
  - Steve Melzer, President of Melzer Consulting
  - Barry Schneider of Denbury Resources
  - Scott Wehner, Manager – Engineering; Andrew Parker, Geoscientists – Permian Basin; and Tom Beebe, Sr. Reservoir Engineer of Whiting Petroleum Corporation
  - Mike Moore, Vice President, External Affairs & Business Development CCS of Blue Source
  - Dr. Robert Trentham, Director, Center for Energy and Economic Diversification, University of Texas of the Permian Basin
  - Brian Hargrove and Barry Petty, Trinity CO_2
  - Michael Rushing, CO_2/EOR Manager, Apache Corporation, and
  - Tom Thurmond, Engineering Manager, Legado Resources

Overall Industry Observations

The industry experts found that the methodology and results of the CO_2-EOR studies of NETL/ARI were reasonable. While a number of excellent suggestions were made as to how specific areas of the methodology could be improved (e.g., current higher costs of CO_2 pipelines), the overall response, as stated by one respondent was "if we were asked to do this, we probably would have done it the same way."

The industry reviewers found the oil recovery efficiencies of 15% to 20% of OOIP for oil reservoirs geologically favorable for CO_2 to be reasonable. (Overall, the NETL/ARI results for "state of art" CO_2-EOR provides 17.5% recovery of OOIP, after eliminating oil reservoirs not favorable for miscible CO_2-EOR.) The industry experts cited examples of CO_2-EOR projects that were recovering 17% to 18% of OOIP and, with additional reservoir surveillance and technology, were looking to push this over 20% of OOIP.

Two specific observations were made with respect to observed oil recovery efficiencies in actual CO2-EOR floods:

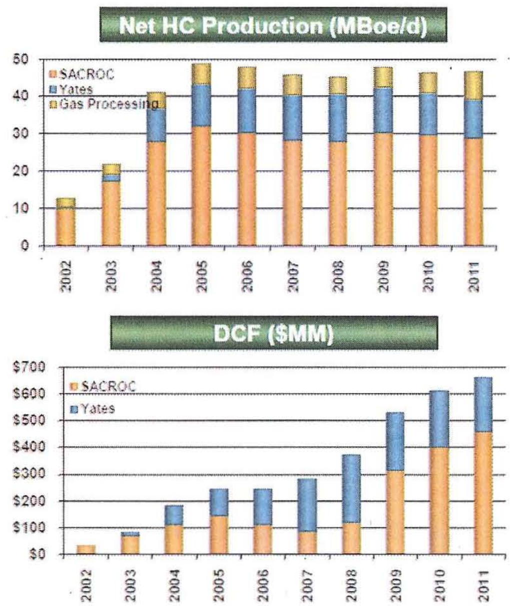
- Whiting noted that their Postle CO_2-EOR project is currently expected to recover 17% to 18% of OOIP and, with application of cross-well seismic and increased use of CO_2 in selected patterns, the company looks to push up the recovery efficiency to the mid-twenties.
- Denbury noted that their oil recovery expectations are for 17% to 18% of OOIP for straight CO_2 flooding. With incorporation of a WAG process at the end of the straight CO_2-flood, Denbury looks to boost oil recoveries to 20% OOIP. Denbury specifically cited the West Heidelberg oil field which already has an expected 18% recovery of OOIP from CO_2-EOR (60% OOIP overall recovery). They are considering converting this field to a WAG process to further increase oil recovery.

The exclusion of NGL production from the liquids production reported for CO_2-EOR projects is one reason reported oil recovery efficiencies are lower than actual total liquids recoveries. (A barrel of NGLs has about two-thirds of the Btu content and sales value of crude oil.) For example:

- The SACROC CO_2-EOR project operated by Kinder Morgan reports (for 2010) about 29,000 barrels per day of oil production and about 16,000 barrels per day of NGL production from the SACROC gas plant. (A small portion of the input stream to the gas plant is from other nearby oil fields.) Adding the NGL production (after adjusting for Btu content) would increase the reported liquids production value by 37 %, see Table B-1.
- Whiting reports that their long-term observation is that CO_2-EOR strips the light ends from the crude oil (the propane, butane, etc.) leading to significantly higher incremental NGL production volumes after the initiation of a CO_2 flood.

Future assessments of the performance of CO_2-EOR would benefit from the incorporation of NGL production into overall oil recovery estimates and economics.

Table B-1. Oil and Gas Segment: Production and DCF



Original Oil in Place (billion Bbls)	
SACROC	2.8
Yates	5.0
Katz	0.23

Gross Production (Bbl/d)	2010	2011
SACROC oil	29,222	29,374
SGP NGLs	15,921	17,001
Yates	24,046	22,500
Katz	284	1,451

DCF ($MM)	2010	2011
SACROC Unit-only	$400	$459
Yates	$213	$203
Katz	$1	$17

Notes: Yates DCF does not include contribution from MKM
Boe: Oil and NGL =1:1, Residue gas sales = 6:1
Gas Processing includes net Boe attributable to our plant interests and processing agreements but excluded from reserve report

Source: KinderMorgan, 2011

Major Recommendations

The industry experts made ten significant recommendations for improving the modeling of "Next Generation" CO_2-EOR.

Recommendation #1. Consider modifying the injected CO_2 to water ratio, including using a larger initial slug of CO_2 or even straight CO_2 in low permeability oil reservoirs, to increase the processing rate and reduce the need to "drill down" the pattern.

Currently, the model uses the same WAG ratio, independent of the permeability (and thus injectivity) of the reservoir, often causing the model to use closer well spacing than currently exists to achieve a 15 to 30 year flood (per pattern).

Modifying the WAG ratio or eliminating the use of water would enable the model to use larger well spacing, reducing the need to drill additional wells and thus improving economics.

The *PROPHET2* model has been revised to set the minimum pattern size to 40 acres, to increase minimum CO_2 injectivity, and to incorporate a larger initial CO_2 slug, as part of a tapered WAG.

Recommendation #2. Consider applying the CO_2 flood to only 80% of the reservoir area to eliminate the low quality edge of the reservoir from being flooded. The exact factor could be related to field size, with large fields having a higher factor of developable acreage.

Currently, the model selects one type pattern and applies the results from this type pattern to the entire reservoir. A key input is the average reservoir net thickness which includes both the thicker central area and the thinner edge area. Reducing the CO_2 flood to the higher quality, thicker pay central area of the oil reservoir would provide somewhat higher recovery per pattern and enable fewer patterns to flood the bulk of the OOIP.

The PROPHET model has been revised to flood only 80% of the field area containing 90% of the OOIP.

Recommendation #3. Consider allowing higher gravity oils to become miscible or near miscible CO_2 candidates due to achieving multi-contact miscibility with time. Currently, lower gravity oil reservoir, say 18° to 20° API, are generally categorized as immiscible floods, relegated to low recovery of the OOIP.

Certain lower gravity floods in relatively shallow oilfields, such as the Eucutta oil field, are achieving higher oil recovery efficiency than would be realized from an immiscible model. A similar lower oil gravity CO_2 flood with higher expected performance is in planning stages for the shallower Wall reservoir in the Salt Creek field in Wyoming. Applying near miscible CO_2 flooding to these lower oil gravity oil reservoirs would provide higher oil recovery efficiencies.

This recommendation has been incorporated, in a preliminary way, into the model, but requires further analytical work.

Recommendation #4. Incorporate the oil resources and production from the Residual Oil Zones (ROZs) into "Next Generation" ROZ. Currently the model only floods the MPZ (main pay zone of the oil reservoir). However, evidence is mounting that the San Andres ROZ in the Permian Basin is of high quality, with a thick pay and favorable oil saturation.

Adding the ROZ of the San Andres formation in the Permian Basin would increase the size of the target oil producible with CO_2-EOR. It would also significantly increase the storage volume for CO_2.

The already performed study of the Permian, Big Horn and Williston basins' ROZ resources (beneath existing fields) will be incorporated into this "Next Generation" study. Further study of ROZ resources, with a particular emphasis on the oil resources held in ROZ "fairways" and on the economic feasibility of producing oil from ROZs would significantly improve the understanding of this important domestic oil resource.

Recommendation #5. Use marginal oil productivity and costs to set the maximum HCPV of CO_2 to be injected.

Currently, the *PROPHET2* model uses 1.0 HCPV for the "State of Art" CO_2-EOR case and uses 1.5 HCPV for the "Next Generation" CO_2-EOR case. Making the volume of CO_2 injected in the "Next Generation" CO_2-EOR case a function of marginal costs would provide a more realistic representation of current EOR operations.

This feature has been incorporated into this "Next Generation" study.

Recommendation #6. Consider including a "combination technology case", involving injection of CO_2 and surfactant, for improving oil recovery from immiscible CO_2-EOR projects, such as Yates.

Currently, oil reservoirs categorized as immiscible are not included in this study. Adding a low-concentration of surfactant slug followed by CO_2 could substantially increase oil recovery efficiency in shallower, immiscible flooded CO_2-EOR projects.

This feature is being investigated for use in subsequent model updates.

Recommendation #7. Increase the size of the initial CO_2 slug to 0.4 HCPV before starting a CO_2 WAG.

Currently, the CO_2 flooding design is to conduct a 1 to 3 WAG for the first 0.4 HCPV of injected CO_2, followed by a 1 to 2.5 WAG for the remaining 0.6 HCPV of injected CO_2. Increasing the volume of the CO_2 slug at the start of the project will provide a quicker oil response and potentially help promote miscibility, helping improve the economics of the CO_2 flood.

The tapered WAG feature has been incorporated into this "Next Generation" study.

Recommendation #8. Modify the CO_2 injection and production algorithm in PROPHET2 to reflect a higher net CO_2 to oil ratio, to account for dead-end pores and loss of CO_2 outside the pattern.

Currently, the model does not include dead-end pore space or loss of CO_2 outside the pattern, thus providing a relatively favorable CO_2 material balance. Reducing the production of CO_2 to about 75% of what would otherwise occur, to account for dead-end pore space and CO_2 losses, would raise the required purchase volumes of CO_2.

This feature has been incorporated into this "Next Generation" CO_2-EOR study.

Recommendation #9. Consider incorporating the higher NGL production achieved from CO_2-EOR floods in the overall economics.

Currently, only the oil production from a CO_2 flood is included in the recovery efficiency and economic calculation. Past experience shows that implementation of CO_2-EOR significantly improves the stripping of light ends from the crude oil.

This feature is being investigated for use in subsequent model updates.

Recommendation #10. Consider using basin-by-basin criteria for establishing the maximum pressure gradient for MMP (minimum miscibility pressure).

Currently, the screening criteria for miscibility use a maximum pressure gradient of 0.6 psi/ft. for all basins. Increasing the pressure gradient to a higher, say 0.7 psi/ft. for the Illinois Basin would enable a shallower, 2,700 reservoir with a MMP of 1,800 psi to be a miscible CO_2 flood (maximum pressure of 1,890 psi) instead of being processed as an immiscible CO_2 flood (maximum pressure of 1,620 psi).

This feature has been incorporated into the "Next Generation" analysis of the Illinois Basin.