Comprehensive, Quantitative Risk Assessment of CO_2 Geologic Sequestration

Project Number DE-FE0001112

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U.S. Department of Energy

National Energy Technology Laboratory
Carbon Storage R&D Project Review Meeting
Developing the Technologies and Building the Infrastructure for CO_2 Storage

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Presentation Outline

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Benefit to the Program

- Program goals being addressed.
  - Develop technologies that will support industries' ability to predict CO_2 storage capacity in geologic formations to within $\pm$ 30 percent.
  - Develop technologies to demonstrate that 99 percent of injected CO_2 remains in the injection zones.
  - Validate risk assessment process models using results from large-scale storage projects to develop risk assessment profiles for specific projects.
- Project benefits statement.
  - This project is developing a comprehensive, quantitative CO_2 risk assessment tool, based on a Failure Modes and Effects Analysis (FMEA) model, that can be customized to assess site-specific projects, integrated with other CO_2 storage assessment tools, and easily modified, improved or expanded. This tool will help identify and characterize risks and risk prevention/mitigation steps and estimate associated costs to ensure 99 percent CO_2 storage permanence in CO_2 sequestration in deep saline aquifers (DSA), enhanced oil recovery (EOR) and enhanced coal bed methane (ECBM).

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Project Overview: Objectives & Goals

- Project Objectives
  - The primary objective of this project is to develop and apply an innovative, advanced, process-based risk assessment model and protocol to determine quantitative risks and predict quantitative impacts for CO_2 geologic sequestration project sites. The model shall be capable of integration with advanced simulation models and MVA technologies.
- Project goals
  - Identify and characterize technical and programmatic risks for CO_2 capture, transportation and sequestration in DSA, EOR and ECBM.
  - Employ probabilistic calculations, process- and system-level simulation models to quantify risks
  - Develop a Quantitative Failure Modes and Effects Analysis (QFMEA) model.
  - Estimate capital, operating and closure costs, potential damage recovery costs, risk mitigation costs and potential cost savings with risk mitigation.
  - Conduct quantitative risk assessments on up to three different sites.

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Project Team

- **Headwaters Clean Carbon Services LLC** – Risk identification and characterization, QFMEA development, financial modeling, estimating potential damage recovery costs and mitigation costs. Project management. Review of overall work product.

- **Faulkner & Flynn (Marsh)** – Refining QFMEA, financial model, estimates of potential damage recovery costs and mitigation costs. Development of insurance schedule for CO_2 sequestration. Review of overall work product.

- **The University of Utah** – Process-level modeling and probability calculations. Review of overall work product.

- **Los Alamos National Laboratory** – System-level modeling. Review of overall work product.

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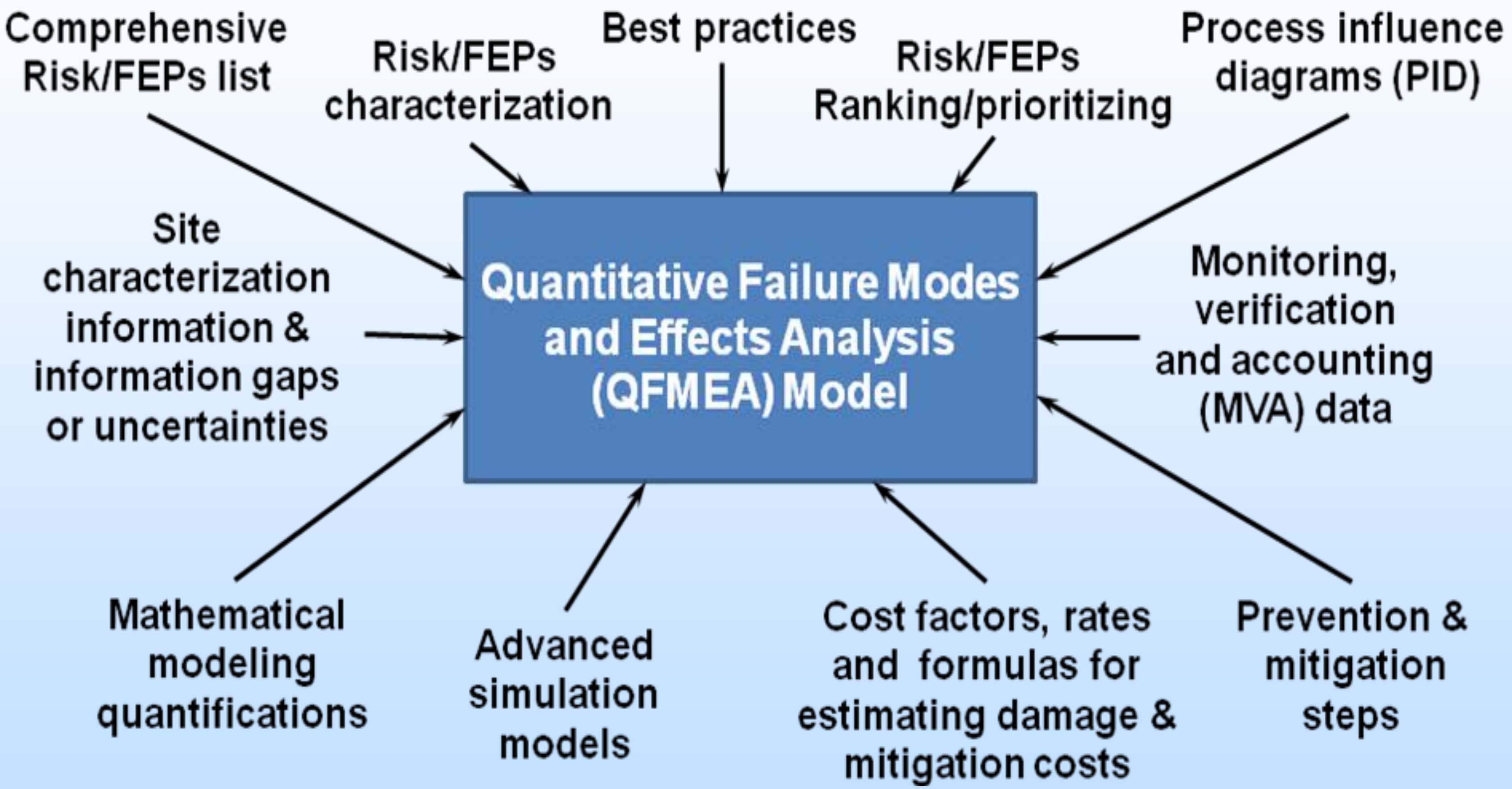
QFMEA Model



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Risk Characterization

- Index number
- Risk area/FEP
- Description of risk/FEP
- Relevance to CO_2 geologic storage
- Site specific information
- Site specific information gaps or uncertainties
- FEPs type (feature, event, process)
- CO_2 storage type (DSA, EOR, ECBM)
- Project phase impacted (site characterization, EPC, startup/operation, post-injection site care)

				Project Specific Information		FEPs Type			Storage Type				Project Phase Impacted				
Index #	Risk Area/FEP	Description	Relevance	Site Specific Information	Information Gaps or Uncertainties	Feature	Event	Process	DSA	EOR	ECBM	All Storage Types	Site Characterization	Eng. Proc. Const. (EPC)	Startup and Operation	Post-Injection Site Care	All Project Phases

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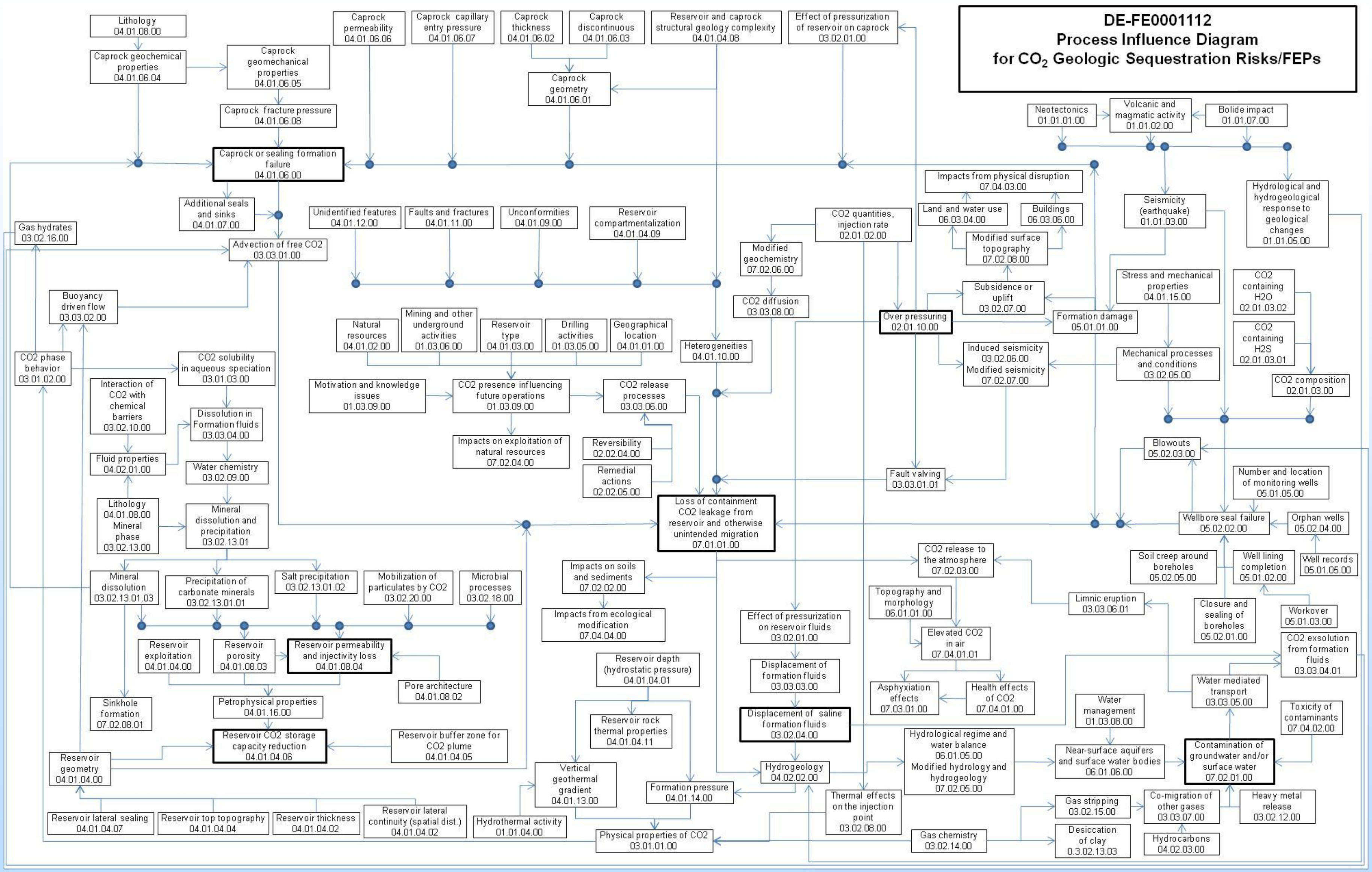
Process Influence Diagrams



Separate PIDs for DSA, EOR and ECBM

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Failure Modes and Effects Analysis (FMEA)

- Potential failure mode
- Cause of failure
- Potential failure effect
- Method of detecting failure
- Prevention and mitigation steps
- Ranking probability of failure (P = 1 to 5)
- Ranking severity of failure (S = 1 to 5)
- Ranking difficulty to detect failure (D = 1 to 5)
- Risk priority number (P x S x D = 1 to 125)

Potential failure mode	Cause of failure	Potential failure effect	Method of detecting failure	Prevention steps	Mitigation steps	Probability of failure (P=1 to 5)	Severity of failure (S=1 to 5)	Difficulty to detect failure (D=1 to 5)	Risk priority number (RPN = P x S x D = 1 to 125)

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Ranking Factors for Risks

Ranking Factor	Probability of Failure Occurring	Severity of Failure Effect	Difficulty of Detecting Failure Early
5	**Likely** – frequency ≥1x10^{-1} per year (one event every 1 to 10 years)	**Catastrophic** – Multiple fatalities. Damages exceeding $100M. Project shut down.	**Almost Impossible** – No known control(s) available to detect failure early.
4	**Possible** – frequency from 1x10^{-2} to 1x10^{-1} per year (one event every 10 to 100 years)	**Serious** – Isolated fatality. Damages $10M-$100M. Project lost time greater than 1 year.	**Low** – Low likelihood current control(s) will detect failure early.
3	**Unlikely** – frequency from 1x10^{-4} to 1x10^{-2} per year (one event every 100 to 10,000 years)	**Significant** – Injury causing permanent disability, Damages exceeding $1M to $10M. Project lost time greater than 1 month. Permit suspension. Area evacuation.	**Moderate** - Moderate likelihood current control(s) will detect failure early
2	**Extremely Unlikely** – frequency from 1x10^{-6} to 1x10^{-4} per year (one event every 10,000 to 1,000,000 years)	**Moderate** – Injury causing temporary disability. Damages $100k to $1M. Project lost time greater than 1 week. Regulatory notice.	**High** – High likelihood current control(s) will detect failure early
1	**Incredible** – frequency <1x10^{-6} per year (less than one event every 1,000,000 years)	**Light** – Minor injury or illness. Damages less than $100k. Project lost time less than 1 week.	**Almost Certain** – Current control(s) almost certain to detect the failure early. Reliable detection controls are known with similar processes.

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QFMEA Model Quantification

Damage Recovery Cost

Human Health and Safety			Natural Resource Damage ($)	Third-Party Property Damage ($)	Owner Property Damage ($)	Owner Business Interruption ($)	Owner Economics ($)	CO_2 Emissions (tonnes and $)	Litigation Costs ($)
Fatalities ($)	Serious Injuries ($)	Minor Injuries ($)							

Prevention/Mitigation Cost Savings

A. Damage Recovery Cost w/o Prevention and Mitigation ($)	B. Damage Recovery Cost w/ Prevention and Mitigation ($)	C. Cost of Prevention and Mitigation ($)	D. Cost Savings with Prevention and Mitigation ($) D = A – B – C

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Quantifying Damage Recovery Costs

Damage Scenario	Fatalities	Serious Injuries	Minor Injuries	Natural Resource Damage	Third-Party Property Damage	Owner Property Damage	Owner Business Interruption	Owner Economics	CO_2 Emissions	Litigation Costs
Leaky borehole										
Leaky fault, fracture zone or permeable pathway										
Well blowout (CO_2 or hydrocarbons)										
Pipeline puncture or rupture (CO_2 $\pm$ H_2S)										
Induced or natural earthquake										
USDW contamination (CO_2/H_2S/brine/heavy metals)										
Soil/sediment contamination										
EOR oil spill										
Accumulation of CO_2 in poorly ventilated low areas or confined spaces										
Water/brine extraction, storage, handling, treating and disposal.										
Fire and/or explosion										

Rates and formulas developed for key damage scenarios based on published data, experience and analogues.

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Cost Factors and Formula Database

- Pore space or land leasing/purchasing costs
- Site characterization and permitting costs
- Compressor and pipeline capital and operating costs
- Well drilling, completion and operating costs
- Monitoring, mitigation and verification (MMV) costs
- DSA, EOR and ECBM capital, operating and closure costs
- Insurance costs
- Business interruption costs
- Remediation costs for loss of containment
- Water/brine extraction, storage, handling, treatment and disposal costs
- Compensation for human fatalities and injuries
- Compensation for wildlife, vegetation, agricultural and natural resource damage
- EOR oil spill damage recovery costs
- Earthquake damage costs
- Lost value of accidental or intentional CO_2 emissions
- Litigation costs

Cost factors and formulas based on published data, vendor estimates, experience and analogues.

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CO_2-DSA Financial Modeling

Project Assumptions

Key Inputs

- Quantity of CO_2 to be injected
- Years of CO_2 injection
- Years of post-injection site care
- CO_2 pipeline length
- CO_2 reservoir dimensions/properties

Key Outputs

- Ultimate extent of the CO_2 plume
- Number of wells
- Project capital costs
- Project operating & maintenance costs
- Financial responsibility required by EPA

Financial Assumptions

Key Inputs

- CO_2 storage fee
- Electricity cost
- Capacity utilization
- Capital contingencies
- Financing cost
- Working capital
- Construction and spending schedules
- Debt/equity ratio, interest rate and term
- Inflation rate

Key Outputs

- Income statement
- Balance sheet
- Cash flow forecast
- Financial ratios
- Internal rate of return

CO$_2$-EOR Financial Modeling

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- Fluid volumes injected and produced (hydrocarbon pore volumes)
- CO_2 purchased, injected and recovered
- Oil, HC, NG and NGL produced and recovered
- Water injected, recovered and disposed
- Power consumption and generation
- Labor
- Active wells
- Capital expenses
- Prices
- Sales volumes
- Revenues
- Operating expenses
- Earnings

SACROC Unit History 2002-2011

Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Total
Fluids Injected											
CO2 injected (HCPV)	0.00904	0.01692	0.02918	0.02618	0.03556	0.03685	0.03727	0.04126	0.04284	0.04284	0.31794
Water injected (HCPV)	0.02075	0.02708	0.03882	0.05145	0.05687	0.05461	0.06138	0.05605	0.04965	0.04965	0.46631
Total fluids injected (HCPV)	0.02979	0.04400	0.06800	0.07763	0.09243	0.09146	0.09865	0.09731	0.09249	0.09249	0.78425
Fluids Produced											
Oil produced (HCPV)	0.00173	0.00265	0.00375	0.00426	0.00407	0.00365	0.0037	0.00399	0.00386	0.00378	0.03544
Water produced (HCPV)	0.01798	0.02528	0.03882	0.05145	0.05687	0.05461	0.06138	0.05605	0.04965	0.04965	0.46174
CO2 produced (HCPV)	0.00315	0.00728	0.01465	0.01512	0.02498	0.02776	0.02618	0.03042	0.03342	0.03625	0.21921
Total fluids produced (HCPV)	0.02286	0.03521	0.05722	0.07083	0.08592	0.08602	0.09126	0.09046	0.08693	0.08968	0.71639
Carbon Dioxide (CO2)											
CO2 injected (MCF/D)	210,975	395,000	681,000	610,959	830,000	860,000	870,000	963,014	1,000,000	1,000,000	
CO2 produced (MCF/D)	73,526	170,000	342,000	352,959	583,000	648,000	611,000	710,014	780,000	846,000	
CO2 purchased (MCF/D)	137,449	225,000	339,000	258,000	247,000	212,000	259,000	253,000	220,000	154,000	
CO2 injected (MCF)	77,005,875	144,175,000	248,565,000	223,000,035	302,950,000	313,900,000	317,550,000	351,500,110	365,000,000	365,000,000	2,708,646,020
CO2 produced (MCF)	26,836,990	62,050,000	124,830,000	128,830,035	212,795,000	236,520,000	223,015,000	259,155,110	284,700,000	308,790,000	1,867,522,135
CO2 purchased (MCF)	50,168,885	82,125,000	123,735,000	94,170,000	90,155,000	77,380,000	94,535,000	92,345,000	80,300,000	56,210,000	841,123,885
CO2 purchased (HCPV)	0.00589	0.00964	0.01452	0.01105	0.01058	0.00908	0.0111	0.01084	0.00943	0.0066	0.09873
Oil, Hydrocarbons and Natural Gas Liquids											
Oil produced (STB/D)	13,059	20,056	28,340	32,200	30,795	27,604	27,995	30,149	29,222	28,627	
HC produced (MCF/D)	18,609	48,000	59,000	71,000	73,000	73,000	70,000	81,000	74,000	72,500	
NGL produced (STB/D)	0	3,700	7,700	9,400	8,900	9,600	8,300	9,400	10,000	8,500	
Oil produced (STB)	4,766,535	7,320,440	10,344,100	11,753,000	11,240,175	10,075,460	10,218,175	11,004,385	10,666,030	10,448,855	97,837,155
HC produced (MCF)	6,792,285	17,520,000	21,535,000	25,915,000	26,645,000	26,645,000	25,550,000	29,565,000	27,010,000	26,462,500	233,639,785
NGL produced (STB)	0	1,350,500	2,810,500	3,431,000	3,248,500	3,504,000	3,029,500	3,431,000	3,650,000	3,102,500	
Gross BOE produced (STB)	4,766,535	8,670,940	13,154,600	15,184,000	14,488,675	13,579,460	13,247,675	14,435,385	14,316,030	13,551,355	125,394,655
Water											
Water injected (STB/D)	229,905	300,000	430,000	570,000	630,025	605,000	680,000	620,959	550,000	550,000	
Water produced (STB/D)	199,170	280,000	430,000	570,000	630,000	605,000	680,000	620,959	550,000	550,000	
Water injected (STB)	83,915,325	109,500,000	156,950,000	208,050,000	229,959,125	220,825,000	248,200,000	226,650,035	200,750,000	200,750,000	1,885,549,485
Water produced (STB)	72,697,050	102,200,000	156,950,000	208,050,000	229,950,000	220,825,000	248,200,000	226,650,035	200,750,000	200,750,000	1,867,022,085
Expansion Capital											
Expansion Capital ($)	183,000,000	244,000,000	278,000,000	196,000,000	204,000,000	256,000,000	347,000,000	258,000,000	227,000,000	257,000,000	2,450,000,000
CO2 capex incl. in opex ($)	14,046,080	29,975,260	52,552,700	59,294,250	71,985,300	57,115,200	88,811,800	65,481,000	76,368,950	63,663,300	579,293,840
Well work incl. in opex ($)	0	0	26,276,350	30,305,950	66,933,700	65,444,500	81,891,400	52,888,500	53,833,850	46568525	424,142,775
Gas handling incl. in opex ($)	0	0	39,985,750	43,482,450	36,624,100	57,115,200	55,363,200	36,518,250	52,581,900	49,515,900	371,186,750
Net capex ($)	168,953,920	214,024,740	159,185,200	62,917,350	28,456,900	76,325,100	120,933,600	103,112,250	44,215,300	97,252,275	1,075,376,635
Prices											
WTI spot price ($/BBL)	26.18	31.08	41.51	56.64	66.05	72.34	99.67	61.95	79.48	94.88	
Weighted avg oil price ($/BBL)	22.45	23.73	25.72	27.36	31.42	36.05	49.42	49.55	59.96	69.73	
Weighted avg NGL price ($/BBL)	18.33	21.77	31.33	39.98	43.9	52.91	63	37.96	51.03	65.61	
Sales Volume											
Net Oil sales (STB/D)	10,317	15,900	23,600	26,700	25,700	23,000	23,300	25,100	24,300	23,800	
Net NGL Sales (STB/D)	0	3,700	7,700	9,400	8,900	9,600	8,300	9,400	10,000	8,500	
Net BOE sales (STB/D)	10,317	19,600	31,300	36,100	34,600	32,600	31,600	34,500	34,300	32,300	
Net Oil sales (STB)	3,765,705	5,803,500	8,614,000	9,745,500	9,380,500	8,395,000	8,504,500	9,161,500	8,869,500	8,687,000	80,926,705
Net NGL Sales (STB)	0	1,350,500	2,810,500	3,431,000	3,248,500	3,504,000	3,029,500	3,431,000	3,650,000	3,102,500	27,557,500
Net BOE sales (STB)	3,765,705	7,154,000	11,424,500	13,176,500	12,629,000	11,899,000	11,534,000	12,592,500	12,519,500	11,789,500	108,484,205
Revenues											
Oil revenue ($)	84,540,077	137,717,055	221,552,080	266,636,880	294,735,310	302,639,750	420,292,390	453,952,325	531,815,220	605,744,510	3,319,625,597
NGL revenue ($)	0	29,400,385	88,052,965	137,171,380	142,609,150	185,396,640	190,858,500	130,240,760	186,259,500	203,555,025	1,293,544,305
Total revenue ($)	84,540,077	167,117,440	309,605,045	403,808,260	437,344,460	488,036,390	611,150,890	584,193,085	718,074,720	809,299,535	4,613,169,902
Expenses											
Taxes other than income ($/BOE)	0.87	0.88	1.00	1.70	2.00	2.30	2.20	0.00	2.00	1.75	
Power ($/BOE net)	2.90	2.56									
Well work ($/BOE net)			2.30	2.30	5.30	5.50	7.10	4.20	4.30	3.95	
CO2 removal ($/BOE net)	0.74	0.61									
CO2 capitalized ($/BOE net)	3.73	4.19	4.60	4.50	5.70	4.80	7.70	5.20	6.10	5.40	
CO2 expensed ($/BOE net)	2.09	2.36	2.60	2.50	3.50	2.50	4.60	2.50	3.20	2.83	
Gas handling ($/BOE net)			3.50	3.30	2.90	4.80	4.80	2.90	4.20	4.20	
Labor ($/BOE net)	0.99	0.73	0.30	0.50	0.50	0.75	1.00	0.75	1.30	1.95	
Other ($/BOE net)	2.83	1.91	0.90	1.30	1.90	1.60	2.30	1.30	1.20	1.30	
Total expenses ($/BOE net)	13.28	12.35	15.20	16.10	21.80	22.25	29.70	16.85	22.30	21.38	
Total expenses ($)	49,989,966	88,358,404	173,652,400	212,141,650	275,312,200	264,752,750	342,559,800	212,183,625	279,184,850	252,059,510	2,150,195,155
Earnings											
Calculated EBITDDA* ($)	34,550,111	78,759,036	135,952,645	191,666,610	162,032,260	223,283,640	268,591,090	372,009,460	438,889,870	557,240,025	2,462,974,748
KM reported EBITDDA ($)**	31,300,000	72,500,000	112,000,000	203,500,000	167,000,000	162,000,000	203,000,000	361,000,000	478,000,000	593,000,000	2,383,300,000
Purchased CO2 Cost Analysis											
CO2 cost ($/BOE net)	5.82	6.55	7.20	7.00	9.20	7.30	12.30	7.70	9.30	8.23	
CO2 cost ($)	21,916,403	46,858,700	82,256,400	92,235,500	116,186,800	86,862,700	141,868,200	96,962,250	116,431,350	97,027,585	
CO2 cost ($/MCF)	0.44	0.57	0.66	0.98	1.29	1.12	1.50	1.05	1.45	1.73	
CO2 cost % of WTI	1.67	1.84	1.60	1.73	1.95	1.55	1.51	1.69	1.82	1.82	
Revenue Analysis											
Calculated revenue ($/BOE net)	22.45	23.36	27.10	30.65	34.63	41.01	52.99	46.39	57.36	68.65	
KM reported revenue ($/BOE net)					35.50	39.50	52.00	47.50	58.00		

*Earnings before interest, taxes, depreciation, depletion and amortization (also called distributable cash flow)
**Including SACROC services and remaining oil and gas assets

SACROC Unit Projection 2012-2021

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
Year	1	2	3	4	5	6	7	8	9	10	
Fluids Injected											
CO2 injected (HCPV)	0.04285	0.04285	0.04285	0.04285	0.04285	0.04285	0.04285	0.04285	0.04285	0.04285	0.4285
Water injected (HCPV)	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.5715
Total fluids injected (HCPV)	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	1.0000
Fluids Produced											
Oil produced (HCPV)	0.00362	0.00326	0.00326	0.00290	0.00259	0.00254	0.00217	0.00181	0.00145	0.00145	0.0251
Water produced (HCPV)	0.05869	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05570	0.05570	0.5701
CO2 produced (HCPV)	0.03769	0.03959	0.03959	0.03995	0.04026	0.04031	0.04068	0.04104	0.04285	0.04285	0.4048
Total fluids produced (HCPV)	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	1.0000
CO2 purchased (HCPV)	0.00516	0.00326	0.00326	0.00290	0.00259	0.00254	0.00217	0.00181	0.00000	0.00000	0.0237
Carbon Dioxide (CO2)											
CO2 injected (MMCF)	365,052	365,052	365,052	365,052	365,052	365,052	365,052	365,052	365,052	365,052	3,650,519
CO2 produced (MMCF)	321,092	337,279	337,279	340,346	342,987	343,413	346,565	349,632	365,052	365,052	3,448,697
CO2 purchased (MMCF)	28,917	14,226	14,226	12,655	11,302	11,084	9,469	7,898	-6,025	-6,025	97,727
CO2 recovered from HC gas (MMSCF)	15,043	13,547	13,547	12,051	10,763	10,555	9,017	7,521	6,025	6,025	104,095
Oil, Hydrocarbons and Natural Gas Liquids											
Oil produced (MSTB)	9,994	9,000	9,000	8,006	7,150	7,012	5,991	4,997	4,003	4,003	69,155
Hydrocarbon gas produced (MMSCF)	24,984	22,499	22,499	20,015	17,875	17,530	14,977	12,492	10,007	10,007	172,887
Natural gas liquids produced (MSTB)	1,098	989	989	880	786	771	658	549	440	440	7,601
Natural Gas											
Natural gas produced (MMSCF)	6,511	5,863	5,863	5,216	4,658	4,568	3,903	3,255	2,608	2,608	45,054
Natural gas consumed (MMSCF)	7,433	7,391	7,391	7,348	7,311	7,305	7,261	7,219	7,176	7,176	73,012
Natural gas sold (MMSCF)	0	0	0	0	0	0	0	0	0	0	0
Natural gas reinjected (MMSCF)	0	0	0	0	0	0	0	0	0	0	0
Natural gas purchased (MMSCF)	923	1,527	1,527	2,132	2,653	2,737	3,359	3,963	4,568	4,568	27,958
Water											
Water injected (MSTB)	231,085	231,085	231,085	231,085	231,085	231,085	231,085	231,085	231,085	231,085	2,310,853
Water produced (MSTB)	237,312	231,085	231,085	231,085	231,085	231,085	231,085	231,085	225,222	225,222	2,305,354
Water disposed of (MSTB)	6,227	0	0	0	0	0	0	0	0	0	6,227
Additional water required (MSTB)	0	0	0	0	0	0	0	0	5,863	5,863	11,726
Power Consumption											
Purchased CO2 booster (kWh/STB oil)	0	0	0	0	0	0	0	0	0	0	
CO2 recycle compression (kWh/STB oil)	177	205	205	232	260	266	312	376	488	488	
Artificial lift for oil and water (kWh/STB oil)	44	47	47	53	59	60	70	84	104	104	
NGL separation (kWh/STB oil)	1	1	1	1	1	1	1	1	1	1	
Water injection and disposal (kWh/STB oil)	28	31	31	35	39	40	46	55	69	69	
CO2 recycle dehydration (kWh/STB oil)	1	1	1	1	1	1	2	2	3	3	
Other (kWh/STB oil produced)	8	9	9	10	11	11	13	16	21	21	
Total power consumption (kWh/STB oil)	259	294	294	331	372	379	445	534	685	685	
Power consumption (MWh)	2,588,070	2,646,404	2,646,404	2,652,352	2,657,474	2,658,300	2,664,414	2,670,382	2,743,653	2,743,653	
Power load (MW)	295	302	302	303	303	303	304	305	313	313	
Internal power supply (MW)	100	100	100	100	100	100	100	100	100	100	
External power supply (MW)	195	202	202	203	203	203	204	205	213	213	
Labor											
Labor (# of employees)	130	130	130	130	130	130	130	130	130	130	
Active Wells											
Injection wells (# wells)	450	450	450	450	450	450	450	450	450	450	
Production wells (# wells)	400	400	400	400	400	400	400	400	400	400	
Total active wells (# wells)	850	850	850	850	850	850	850	850	850	850	
Capital Expenses											
New injection wells (# wells)	25	23	23	20	18	18	15	13	10	10	175
New production wells (# wells)	25	23	23	20	18	18	15	12	10	10	174
Conversion of producers to injectors (# wells)	50	40	40	40	36	30	30	25	20	20	331
New injection wells ($ million)	36.233	34.001	34.681	30.760	28.238	28.803	24.482	21.642	16.981	17.320	273
New production wells ($ million)	37.140	34.852	35.549	31.531	28.945	29.524	25.095	20.478	17.406	17.754	278
Conversions ($ million)	5.830	4.757	4.852	4.949	4.544	3.862	3.939	3.348	2.732	2.787	42
Total capital expenses ($ million)	79.203	73.610	75.082	67.240	61.727	62.189	53.517	45.469	37.119	37.862	593
Prices											
WTI crude oil price ($/bbl)	90.00	91.80	93.64	95.51	97.42	99.37	101.35	103.38	105.45	107.56	
Adjusted crude oil price ($/bbl)	89.85	91.65	93.49	95.36	97.27	99.22	101.20	103.23	105.30	107.41	
Hedged oil price ($/bbl)	76.50	78.03	79.59	81.18	82.81	84.46	86.15	87.87	89.63	91.42	
Realized weighted average oil price ($/bbl)	80.64	82.25	83.90	85.58	87.29	89.04	90.82	92.64	94.49	96.38	
Natural gas liquids price ($/bbl)	62.10	63.34	64.61	65.90	67.22	68.56	69.93	71.33	72.76	74.22	
Natural gas price ($/MSCF)	2.50	2.55	2.60	2.65	2.71	2.76	2.82	2.87	2.93	2.99	
Sales Volumes											
Gross oil sold (MSTB)	9994	9000	9000	8006	7150	7012	5991	4997	4003	4003	69,155
Net oil sold (MSTB)	8328	7500	7500	6671	5958	5843	4992	4164	3336	3336	57,627
Natural gas liquids sold (MSTB)	1098	989	989	880	786	771	658	549	440	440	7,601
Natural gas sold (MMSCF)	0	0	0	0	0	0	0	0	0	0	0
Net barrel of oil equivalent (MBOE net)	9,426	8,489	8,489	7,551	6,744	6,614	5,650	4,713	3,776	3,776	65,228
Revenues											
Oil revenues ($ million)	805.871	740.252	755.065	685.125	624.132	624.331	544.058	462.881	378.236	385.804	6005.755
Natural gas liquids revenue ($ million)	68.215	62.660	63.913	57.992	52.829	52.845	46.050	39.179	32.014	32.654	508.350
Natural gas revenues ($ million)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gross revenues ($ million)	874.085	802.911	818.978	743.117	676.960	677.176	590.109	502.059	410.250	418.459	6514.104
Royalties ($ million)	-134.339	-123.400	-125.869	-114.210	-104.043	-104.076	-90.695	-77.162	-63.052	-64.314	-1001.159
Production (severance) taxes ($ million)	-18.583	-17.070	-17.411	-15.799	-14.392	-14.397	-12.546	-10.674	-8.722	-8.896	-138.490
Net revenues ($ million)	721.164	662.441	675.697	613.108	558.526	558.703	486.868	414.223	338.476	345.249	5374.455
Expenses											
Labor ($ million)	9.360	9.547	9.738	9.933	10.132	10.334	10.541	10.752	10.967	11.186	102.489
Power ($ million)	120.244	126.219	128.744	131.697	134.664	137.412	140.573	143.794	151.823	154.859	1370.029
Purchased natural gas ($ million)	2.307	3.895	3.973	5.657	7.179	7.555	9.456	11.382	13.381	13.648	78.431
Well O&M excl. labor($ million)	41.640	42.473	43.322	44.189	45.072	45.974	46.893	47.831	48.788	49.764	455.946
Other ($ million)	57.081	59.413	60.601	61.940	63.289	64.573	66.002	67.459	70.526	71.936	642.821
Purchased CO2 ($ million)	50.604	25.393	25.901	23.502	21.409	21.416	18.662	15.878	-12.355	-12.602	177.809
Capital expenses ($ million)	79.203	73.610	75.082	67.240	61.727	62.189	53.517	45.469	37.119	37.862	593.017
Total expenses ($ million)	360.439	340.551	347.362	344.157	343.472	349.452	345.645	342.564	320.248	326.653	3420.543
Earnings											
EBITDDA* ($ million)	360.725	321.891	328.336	268.951	215.053	209.251	141.224	71.659	18.228	18.595	1953.912

High lighted cells are input values.
*Earnings before interest, taxes, depreciation, depletion and amortization (also called distributable cash flow)

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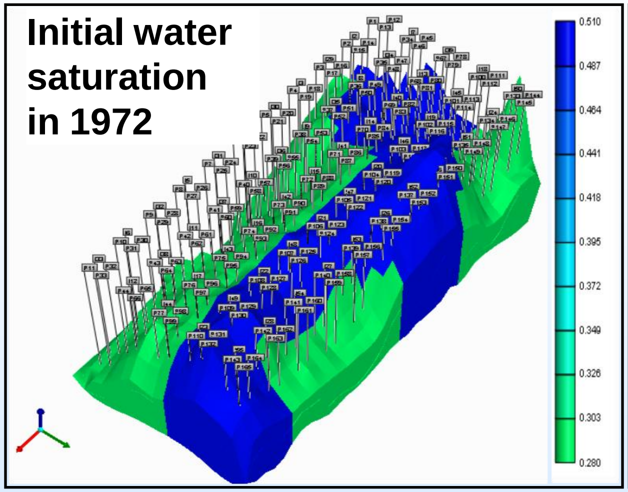
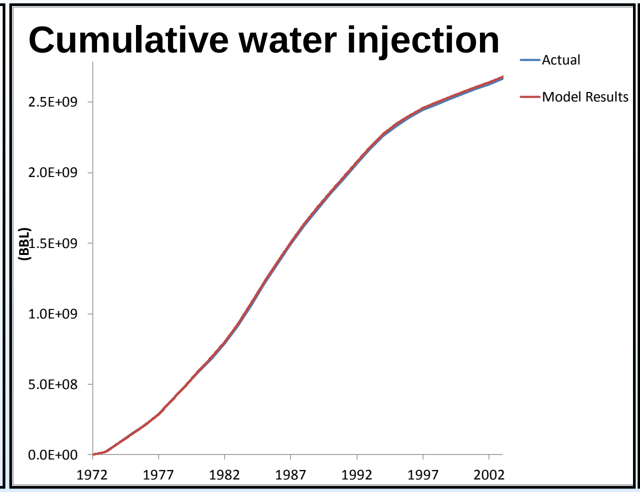
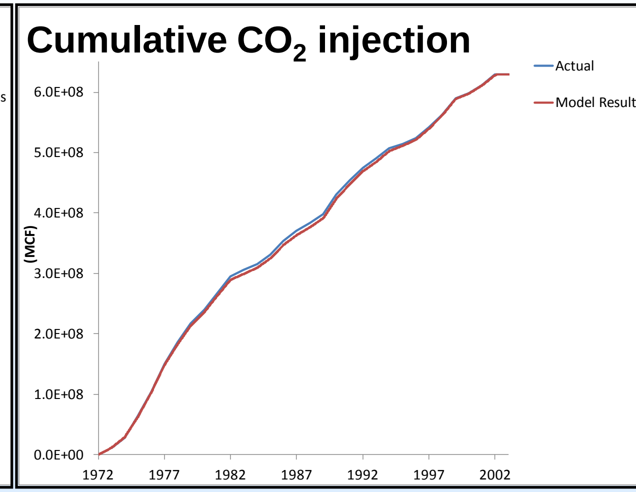
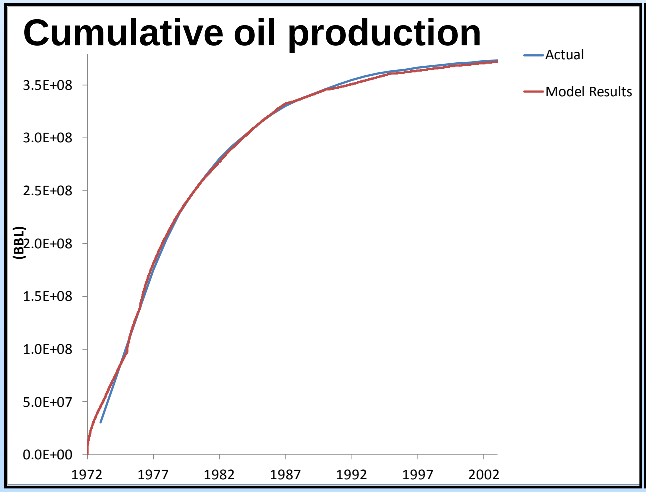
CO_2-EOR Process-Level Modeling

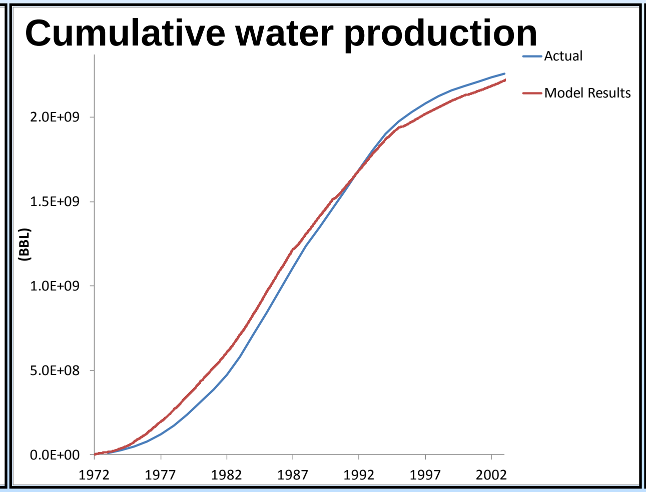
History Match of SACROC Northern Platform Area 1972-2002

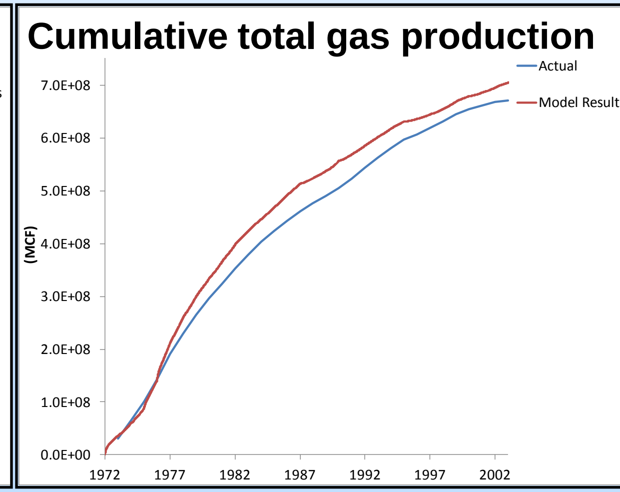






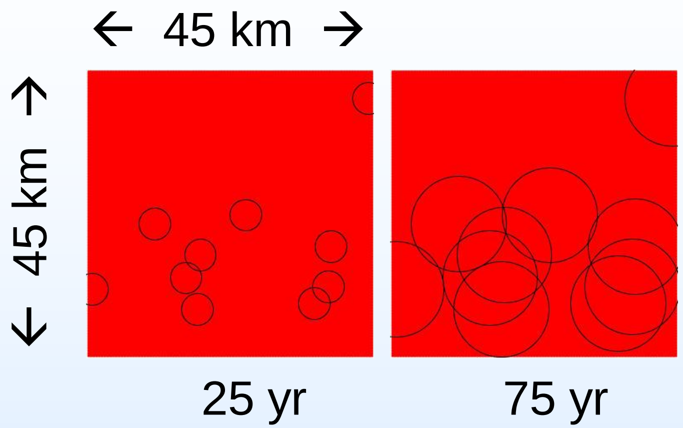






Based on actual field data for 639 wells. Simulation software: CMG

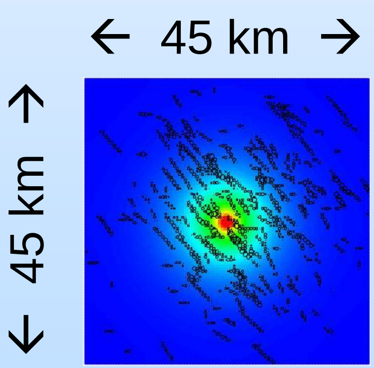
System-Level Modeling



Modeling leaky wells

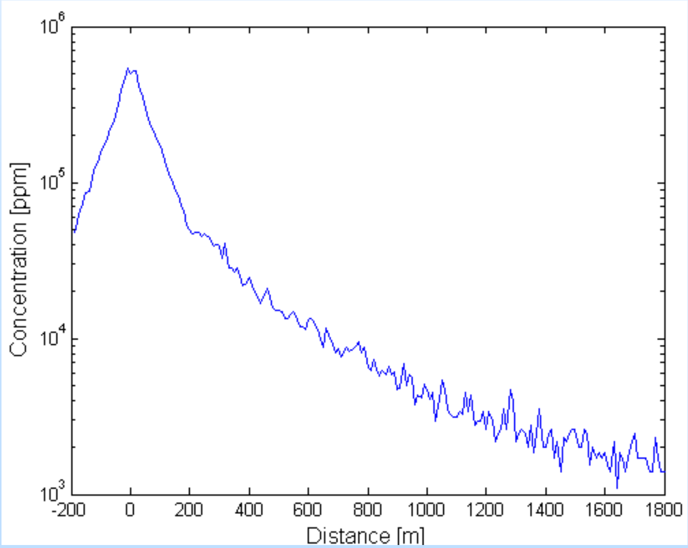
Evolution of CO_2/brine leakage over time

Modeling multiple stacked sinks & seals



Modeling leaky faults

Brine leakage through random faults (colors indicate fluid pressure at top of reservoir)



Modeling pipeline leaks & ruptures

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Quantitative Risk Assessment

1. Gather site-specific information
2. Input site-specific information into the FMEA model
3. Identify information gaps or uncertainties
4. Adjust failure modes, causes, severity effect and methods of detection to the site-specific case
5. Eliminate risk areas that are not applicable
6. Identify relevant site-specific risk prevention and mitigation steps
7. Develop and run site-specific process-level, system-level and financial models to quantify probability, severity and cost factors.
8. Input potential damage recovery costs (w/o and w/ risk mitigation), risk mitigation costs and potential cost savings (cost/benefit analysis) into the QFMEA model.
9. Rank and prioritize risk areas for site-specific conditions based on probability of failure occurring, severity of failure effect and difficulty of detecting failure early.
10. Submit results to a cross-functional team of experts for review for completeness and accuracy.
11. Use results to manage risks during design, construction, operation and closure.
12. Update and revise as more information becomes available or conditions change.

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Accomplishments to Date

- Identified and characterized a comprehensive list of technical and programmable risks for CO_2 capture, transport and sequestration in DSA, EOR and ECBM.
- Developed and employed probability calculations, process- and system-level simulation models, and shortcut calculations to quantify risks.
- Developed a comprehensive Quantitative Failure Modes and Effects Analysis (QFMEA) model for CO_2 capture, transport, and sequestration for DSA, EOR and ECBM.
- Developed financial models for CO_2 DSA and EOR to quantify capital and operating costs.
- Developed an insurance schedule for CO_2 DSA, EOR and ECBM to quantify insurance costs.
- Developed cost factors to estimate potential damage recovery costs, mitigation costs and potential cost savings associated with mitigation for DSA, EOR and ECBM.
- Developed a process-level, history-match model and preliminary QFMEA for the SACROC Northern Platform Area CO_2-EOR site.

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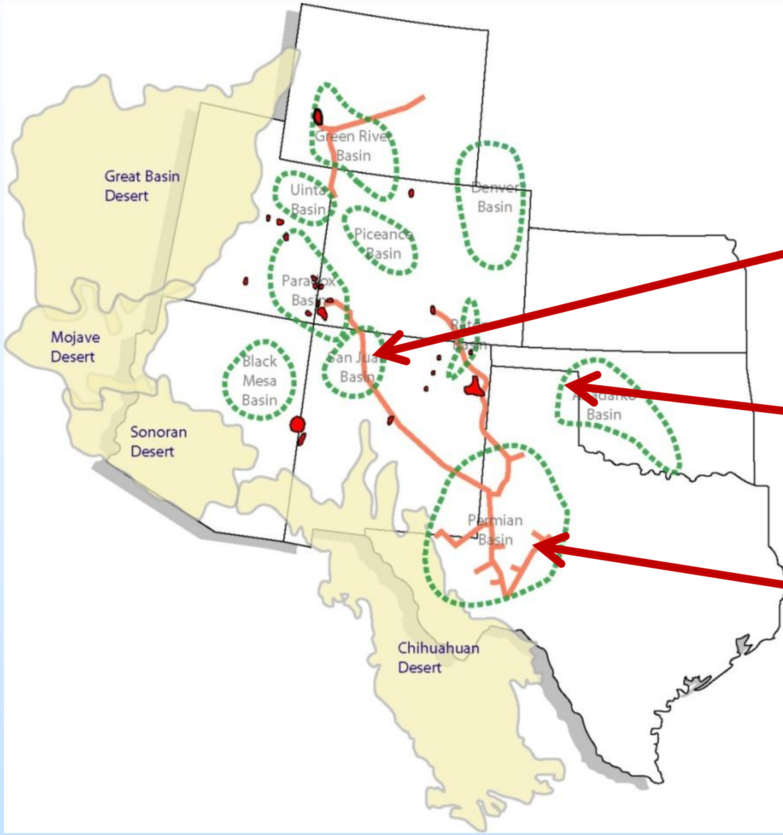
Future Plans



Complete quantitative risk assessment on three different sites.

- Early CO_2 ECBM, Pump Canyon Unit, San Juan Basin, NM
- Early CO_2 EOR, Farnsworth Unit, Anadarko Basin, TX
- Mature CO_2 EOR, SACROC Unit, Permian Basin, TX

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Summary

- Key Findings
  - QFMEA is an effective tool for quantitative risk assessment and generates the necessary thought process for risk management during design, construction, operation and closure.
  - QFMEA has been quantitatively verified against historical and existing field conditions.
  - CO_2 sequestration in deep saline aquifers is cost prohibitive under current regulatory requirements and energy policy.
  - SACROC Northern Platform Area is a low risk CO_2-EOR operation due to nearly ideal site conditions, long-term operating experience and extent of technical knowledge.
- Lessons Learned
  - Operators are reluctant to sponsor third-party risk assessments unless they can see a positive impact on their bottom line.
  - Location, location, location. Most CO_2 sequestration risks can be avoided by proper site selection.

APPENDIX

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Project Schedule

Description	Work Days	Budget Period 1												Budget Period 2												Budget Period 3																					BP 4		
		FY2010												FY2011												FY2012												FY2013											
		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S
Project Management, Planning and Reporting																																																	
Update the Project Management Plan	65	■	■	■																																													
Planning and Reporting	865				■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Final report submitted to DOE																																																	◊
Identify and Characterize Risks																																																	
List of Risks	65	■	■	■																																													
Comprehensive risk list submitted to DOE					◊																																												
Features, Events and Processes	63				■	■	■																																										
FEPS registry submitted to DOE								◊																																									
Risk Characterization	65							■	■	■																																							
Risk characterization database submitted to DOE											◊																																						
Process Influence Diagrams	66										■	■	■																																				
Process influence diagrams submitted to DOE														◊																																			
Risk Quantification by Mathematical Modeling																																																	
Develop Process-Level Models	260							■	■	■	■	■	■	■	■	■	■	■	■																														
Develop System-Level Models	260							■	■	■	■	■	■	■	■	■	■	■	■																														
Probabilistic Calculations	260							■	■	■	■	■	■	■	■	■	■	■	■																														
Functioning mathematical models. Summary reports on mathematical modeling submitted to DOE																				◊																													
Failure Modes and Effects Analysis (FMEA) Model																																																	
Set up FMEA and Prioritize Risks	130																■	■	■	■	■	■																											
Functioning FMEA model. FMEA report submitted to DOE																							◊																										
Evaluate the Impact of Risk Mitigation	130																						■	■	■	■	■	■																					
Risk Mitigation Cost Savings																																																	
Develop Method for Damage Recovery and Cost Savings	130																						■	■	■	■	■	■																					
Report on risk mitigation cost savings submitted to DOE																													◊																				
Application of Risk Assessment Model																																																	
Risk Assessment of CO2 Sequestration Sites	455																												■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
CQRA report for Site A submitted to DOE																																						◊											
CQRA report for Site B submitted to DOE																																												◊					
CQRA report for Site C submitted to DOE																																																	◊

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