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Cost and Performance Baseline for Fossil Energy Plants

Volume 3 Executive Summary: Low Rank Coal and Natural Gas to Electricity

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COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 3 EXECUTIVE SUMMARY: LOW RANK COAL AND NATURAL GAS TO ELECTRICITY

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NETL Viewpoint

Background

The goal of Fossil Energy Research, Development, and Demonstration (RD&D) is to ensure the availability of ultra-clean ("zero" emissions), abundant, low-cost, domestic electricity and energy (including hydrogen) to fuel economic prosperity and strengthen energy security. A broad portfolio of technologies is being developed within the Clean Coal Program to accomplish this objective. Ever increasing technological enhancements are in various stages of the research "pipeline," and multiple paths are being pursued to create a portfolio of promising technologies for development, demonstration, and eventual deployment. The technological progress of recent years has created a remarkable new opportunity for coal. Advances in technology are making it possible to generate power from fossil fuels with great improvements in the efficiency of energy use while at the same time significantly reducing the impact on the environment, including the long-term impact of fossil energy use on the Earth's climate. The objective of the Clean Coal RD&D Program is to build on these advances and bring these building blocks together into a new, revolutionary concept for future coal-based power and energy production.

Objective

To establish baseline performance and cost estimates for today's fossil energy plants, it is necessary to look at the current state of technology. Such a baseline can be used to benchmark the progress of the Fossil Energy RD&D portfolio. This study provides an accurate, independent assessment of the cost and performance for Integrated Gasification Combined Cycle (IGCC), Pulverized Coal (PC), Circulating Fluidized Bed Combustor (CFBC), and Natural Gas Combined Cycle (NGCC) plants with and without carbon dioxide (CO_2) capture and sequestration operating at sites in Montana and North Dakota. The Montana coal plants use Powder River Basin (PRB) coal and the minemouth North Dakota coal plants use North Dakota lignite (NDL) coals.

Approach

The power plant configurations analyzed in this study were modeled using the ASPEN Plus® (Aspen) modeling program. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, cost and performance data from design/build utility projects, and/or best engineering judgment. Capital and operating costs were estimated by WorleyParsons based on simulation results and through a combination of existing vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. Operation and maintenance (O&M) costs and the cost for transporting, storing, and monitoring (TS&M) carbon dioxide (CO_2) in the cases with carbon capture were also estimated based on reference data and scaled estimates. The cost of electricity (COE) was determined for all plants assuming investor-owned utility (IOU) financing. The initial results of this analysis were subjected to a significant peer review by industry experts, academia and government research and regulatory agencies. Based on the feedback from these experts, the report was updated both in terms of technical content and revised costs.

Fossil Energy RD&D aims at improving the performance and cost of clean coal power systems including the development of new approaches to capture and sequester greenhouse gases (GHGs). Improved efficiencies and reduced costs are required to improve the competitiveness of these systems in today's market and regulatory environment as well as in a carbon constrained scenario. The results of this analysis provide a starting point from which to measure the progress of RD&D achievements.

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EXECUTIVE SUMMARY

The objective of this report is to present an accurate, independent assessment of the cost and performance of Low-Rank Coal-Fired Power Systems, specifically integrated gasification combined cycle (IGCC), pulverized coal (PC) and circulating fluidized bed (CFB) plants plus natural gas combined cycle (NGCC) plants at different elevations, using a consistent technical and economic approach that accurately reflects current or near term market conditions. This Executive Summary covers all the technology types that make up the Low Rank Coal Study, which is Volume 3 of a four volume series consisting of the following:

- Volume 1: Bituminous Coal and Natural Gas to Electricity
- Volume 2: Coal to Synthetic Natural Gas and Ammonia (Various Coal Ranks)
- Volume 3: Low Rank Coal and Natural Gas to Electricity
- Volume 4: Bituminous Coal to Liquid Fuels with Carbon Capture

Volume 3 was published in 3 sub volumes and this Executive Summary encompasses all three sub volumes:

- Volume 3a: IGCC Cases [1]
- Volume 3b: Comubustion Cases [2]
- Volume 3c: NGCC Cases [3]

The cost and performance of the various fossil fuel-based technologies will most likely determine which combination of technologies will be utilized to meet the demands of the power market. Selection of new generation technologies will depend on many factors, including:

- Capital and operating costs
- Overall energy efficiency
- Fuel prices
- Cost of electricity (COE)
- Availability, reliability, and environmental performance
- Current and potential regulation of air, water, and solid waste discharges from fossil-fueled power plants.
- Market penetration of clean coal technologies that have matured and improved as a result of recent commercial-scale demonstrations under the Department of Energy's (DOE) Clean Coal Programs

Exhibit ES-1 shows the 28 cases in this study, one for each technology configuration, using either PRB or lignite coal at one of two site conditions, with and without CO_2 capture. This includes configurations for 12 oxygen-blown IGCC plants based on the Shell Coal Gasification Process (SCGP), Transport Integrated Gasification (TRIG™) gasifier, Siemens Fuel Gasifier (SFG), and Conoco Phillips (CoP) E-Gas™ gasifiers. Twelve combustion power plant configurations were analyzed including supercritical (SC) and ultra-supercritical (USC) pulverized coal (PC) plants and SC CFB plants. NGCC cases were also analyzed at each site.

The methodology included performing steady-state simulations of the various technologies using the Aspen Plus® (Aspen) modeling software. The resulting mass and energy balance data from the Aspen model were used to size major pieces of equipment. These equipment sizes formed the basis for cost estimating. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and best engineering judgment. Capital and operating costs were estimated based on simulation results and through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. Baseline fuel costs for this analysis were determined using data from the Energy Information Administration's (EIA) 2008 Annual Energy Outlook (AEO). The first year of capital expenditure (2007) delivered costs used were $0.84/gigajoule (GJ) ($0.89/million British thermal unit [MMBtu]) for Powder River Basin (PRB) coal and $0.79/GJ ($0.83/MMBtu) for North Dakota Lignite (NDL), both on a higher heating value (HHV) basis and in June 2007 United States (US) dollars.

Exhibit ES-1 Case Descriptions

Case	Gasifier / Boiler	Fuel	Steam Cycle, psig/^{o}F/^{o}F	Sulfur Removal	CO_2 Separation
S1A	Shell SCGP	PRB	1800/1050/1050	Sulfinol-M	-
S1B	Shell SCGP	PRB	1800/1000/1000	Selexol	Selexol 2nd stage
L1A	Shell SCGP	NDL	1800/1050/1050	Sulfinol-M	-
L1B	Shell SCGP	NDL	1800/1000/1000	Selexol	Selexol 2nd stage
S2A	TRIG™	PRB	1800/1050/1050	Sulfinol-M	-
S2B	TRIG™	PRB	1800/1000/1000	Selexol	Selexol 2nd stage
S3A	Siemens SFG	PRB	1800/1050/1050	Sulfinol-M	-
S3B	Siemens SFG	PRB	1800/1000/1000	Selexol	Selexol 2nd stage
L3A	Siemens SFG	NDL	1800/1050/1050	Sulfinol-M	-
L3B	Siemens SFG	NDL	1800/1000/1000	Selexol	Selexol 2nd stage
S4A	CoP E-Gas™	PRB	1800/1050/1050	MDEA	-
S4B	CoP E-Gas™	PRB	1800/1000/1000	Selexol	Selexol 2nd stage
S12A	SC PC	PRB	3500/1100/1100	Spray Dryer FGD	-
S12B	SC PC	PRB	3500/1100/1100	Spray Dryer FGD	Amine Absorber
L12A	SC PC	NDL	3500/1100/1100	Spray Dryer FGD	-
L12B	SC PC	NDL	3500/1100/1100	Spray Dryer FGD	Amine Absorber
S13A	USC PC	PRB	4000/1200/1200	Spray Dryer FGD	-
S13B	USC PC	PRB	4000/1200/1200	Spray Dryer FGD	Amine Absorber
L13A	USC PC	NDL	4000/1200/1200	Spray Dryer FGD	-
L13B	USCPC	NDL	4000/1200/1200	Spray Dryer FGD	Amine Absorber
S22A	SC CFB	PRB	3500/1100/1100	Spray Dryer FGD	-
S22B	SC CFB	PRB	3500/1100/1100	In-bed Limestone	Amine Absorber
L22A	SC CFB	NDL	3500/1100/1100	In-bed Limestone	-
L22B	SC CFB	NDL	3500/1100/1100	In-bed Limestone	Amine Absorber
S31A	NGCC	NG	2400/1050/1050	-	-
S31B	NGCC	NG	2400/1050/1050	-	Amine Absorber
L31A	NGCC	NG	2400/1050/1050	-	-
L31B	NGCC	NG	2400/1050/1050	-	Amine Absorber

All plant configurations were evaluated based on installation at a greenfield site (Montana [MT], 3400 ft elevation, for cases using PRB coal and North Dakota [ND], 1900 ft elevation, for cases using lignite). To compare the plants on an equivalent basis, it was assumed that these plants would be dispatched any time they are available. The study capacity factor (CF) was chosen to reflect the maximum availability demonstrated for the specific plant type, i.e., 80 percent for IGCC and 85 percent for PC and NGCC configurations. Since variations in fuel costs and other factors can influence dispatch order and CF, sensitivity of the cost of electricity (COE) to CF was evaluated and is presented later in this Executive Summary in Exhibit ES-18 and Exhibit ES-19. Only the Shell and Siemens IGCC configurations are modeled at the North Dakota site with lignite coal, so averages and comparisons between the two sites in later discussions can have a different basis.

The nominal net plant output for this study is set at 550 megawatts (MW). The actual net output varies between technologies because the combustion turbines (CTs) in the IGCC and NGCC cases are manufactured in discrete sizes, but the boilers and steam turbines in the PC cases are available in a wide range of capacities. The result is that all of the PC cases have a net output of 550 MW, but the IGCC cases have net outputs ranging from 445 (Case S3B) to 617 MW (Case L1A). The range in IGCC net output is caused by the higher auxiliary load incurred in the CO_2 capture cases, primarily due to CO_2 compression, and the need for extraction steam in the water-gas shift (WGS) reactions, which reduces steam turbine output. Higher auxiliary load and extraction steam requirements can be accommodated in the PC cases (larger boiler and steam turbine) but not in the IGCC cases where it is impossible to maintain a constant net output from the steam cycle given the relatively fixed heat recovery from the CT. Likewise, the NGCC cases have a net output range of 435 (Case S31B) to 547 MW (Case L31A) because of the CT constraint and the CO_2 capture extraction steam and electrical auxiliaries.

Exhibit ES-2 shows the cost, performance, and environmental profile results summary for all IGCC cases, Exhibit ES-3 displays the results for the combustion cases, and Exhibit ES-4 displays the results for the NGCC cases. The results are discussed below in the following order:

- Performance (efficiency and raw water consumption)
- Cost (plant capital costs and COE)
- Environmental profile

Exhibit ES-2 Results Summary for IGCC Cases

	Shell IGCC Cases				TRIG IGCC Cases		Siemens IGCC Cases				CoP IGCC Cases	
PERFORMANCE	**S1A**	**L1A**	**S1B**	**L1B**	**S2A**	**S2B**	**S3A**	**L3A**	**S3B**	**L3B**	**S4A**	**S4B**
CO_2 Capture	0%	90%	0%	90%	0%	83%	0%	90%	0%	90%	0%	90%
Gross Power Output (kW_e)	696,700	752,600	663,400	713,300	652,700	621,300	622,200	678,800	634,700	676,900	738,300	727,200
Auxiliary Power Requirement (kW_e)	124,020	135,900	191,790	213,240	107,280	160,450	117,480	135,680	189,410	210,390	133,460	212,130
Net Power Output (kW_e)	572,680	616,700	471,610	500,060	545,420	460,850	504,720	543,120	445,290	466,510	604,840	515,070
Coal Flowrate (lb/hr)	542,713	760,093	585,970	814,029	545,197	577,946	531,119	743,918	579,796	801,651	656,228	675,058
HHV Thermal Input (kW_{th})	1,362,134	1,474,011	1,470,704	1,578,608	1,368,368	1,450,564	1,333,034	1,442,644	1,455,207	1,554,603	1,647,041	1,694,303
Net Plant HHV Efficiency (%)	42.0%	41.8%	32.1%	31.7%	39.9%	31.8%	37.9%	37.6%	30.6%	30.0%	36.7%	30.4%
Net Plant HHV Heat Rate (Btu/kWh)	8,116	8,156	10,641	10,772	8,560	10,740	9,012	9,063	11,151	11,371	9,292	11,224
Raw Water Withdrawal (gpm/MW_{net})	3.1	3.0	7.2	7.8	3.7	6.5	4.5	4.0	9.0	8.9	5.4	8.4
Process Water Discharge (gpm/MW_{net})	0.8	0.8	1.4	1.6	0.8	1.0	1.1	1.1	1.6	1.7	1.1	1.5
Raw Water Consumption (gpm/MW_{net})	2.3	2.2	5.9	6.2	2.9	5.5	3.4	2.9	7.4	7.2	4.3	6.9
CO_2 Emissions (lb/MMBtu)	214	219	22	22	211	36	214	219	22	22	213	22
CO_2 Emissions (lb/MWh_{gross})	1,426	1,461	165	170	1,507	287	1,563	1,585	172	175	1,620	174
CO_2 Emissions (lb/MWh_{net})	1,735	1,783	233	242	1,803	386	1,927	1,981	246	255	1,977	245
SO_2 Emissions (lb/MMBtu)	0.0023	0.0023	0.0009	0.0010	0.0019	0.0009	0.0039	0.0021	0.0009	0.0010	0.0016	0.0009
SO_2 Emissions (lb/MWh_{gross})	0.015	0.015	0.007	0.007	0.013	0.007	0.029	0.016	0.007	0.008	0.012	0.007
NOx Emissions (lb/MMBtu)	0.062	0.063	0.050	0.049	0.059	0.049	0.061	0.061	0.051	0.050	0.052	0.044
NOx Emissions (lb/MWh_{gross})	0.412	0.418	0.381	0.371	0.422	0.390	0.444	0.445	0.397	0.391	0.398	0.348
PM Emissions (lb/MMBtu)	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071
PM Emissions (lb/MWh_{gross})	0.047	0.047	0.054	0.054	0.051	0.057	0.052	0.051	0.056	0.056	0.054	0.056
Hg Emissions (lb/TBtu)	0.351	0.560	0.351	0.560	0.351	0.351	0.351	0.560	0.351	0.560	0.351	0.351
Hg Emissions (lb/MWh_{gross})	2.34E-06	3.74E-06	2.66E-06	4.23E-06	2.51E-06	2.80E-06	2.57E-06	4.06E-06	2.75E-06	4.39E-06	2.67E-06	2.79E-06
COST												
Total Plant Cost (2007\$/kW)	2,506	2,539	3,480	3,584	2,236	3,019	2,610	2,656	3,533	3,626	2,265	3,144
Total Overnight Cost (2007\$/kW)	3,056	3,094	4,253	4,378	2,728	3,691	3,185	3,239	4,318	4,430	2,771	3,851
Bare Erected Cost	1,914	1,941	2,610	2,692	1,692	2,228	2,006	2,044	2,654	2,730	1,737	2,357
Home Office Expenses	177	179	242	250	157	207	186	189	247	254	162	221
Project Contingency	343	349	486	502	305	421	359	367	493	508	306	431
Process Contingency	72	69	142	141	83	164	60	56	139	135	60	135
Owner's Costs	550	556	773	794	492	672	575	583	785	804	505	706
Total Overnight Cost (2007\$x1,000)	1,750,189	1,908,200	2,005,883	2,189,363	1,488,063	1,701,132	1,607,607	1,759,016	1,922,741	2,066,464	1,675,790	1,983,369
Total As Spent Capital (2007\$/kW)	3,484	3,527	4,849	4,991	3,110	4,208	3,631	3,692	4,922	5,050	3,159	4,390
COE (mills/kWh, 2007\$)[1]	83.2	83.5	119.7	121.9	74.5	105.2	86.8	87.3	121.7	123.7	78.7	112.3
CO_2 TS&M Costs	0.0	0.0	6.0	5.7	0.0	5.9	0.0	0.0	6.3	6.2	0.0	5.8
Fuel Costs	7.2	6.7	9.5	8.9	7.6	9.5	8.0	7.5	9.9	9.4	8.3	10.0
Variable Costs	8.0	8.2	10.6	11.1	6.8	8.8	8.2	8.4	10.6	11.1	8.3	10.9
Fixed Costs	13.7	13.6	18.3	18.6	11.8	15.5	14.1	14.0	18.4	18.6	13.0	17.4
Capital Costs	54.2	54.9	75.4	77.6	48.4	65.4	56.5	57.4	76.6	78.5	49.1	68.3
LCOE (mills/kWh, 2007\$)[1]	105.4	105.8	151.8	154.5	94.5	133.3	110.0	110.7	154.3	156.9	99.8	142.4

[1] CF is 80% for IGCC cases

Exhibit ES-3 Results Summary for Combustion Cases

	Supercritical Pulverized Coal Boiler				Ultra-supercritical Pulverized Coal Boiler				Supercritical CFB			
PERFORMANCE	**S12A**	**L12A**	**S12B**	**L12B**	**S13A**	**L13A**	**S13B**	**L13B**	**S22A**	**L22A**	**S22B**	**L22B**
CO_2 Capture	0%	0%	90%	90%	0%	0%	90%	90%	0%	0%	90%	90%
Gross Power Output (kW_e)	582,700	584,700	673,000	683,900	581,500	583,200	665,400	675,200	578,400	578,700	664,000	672,900
Auxiliary Power Requirement (kW_e)	32,660	34,640	122,940	133,850	31,430	33,170	115,320	125,170	28,330	28,670	113,990	122,820
Net Power Output (kW_e)	550,040	550,060	550,060	550,050	550,070	550,030	550,080	550,030	550,070	550,030	550,010	550,080
Coal Flowrate (lb/hr)	566,042	755,859	811,486	1,110,668	549,326	731,085	764,212	1,043,879	563,307	745,997	801,270	1,095,812
HHV Thermal Input (kW_{th})	1,420,686	1,465,801	2,036,717	2,153,863	1,378,732	1,417,757	1,918,067	2,024,343	1,413,821	1,446,676	2,011,075	2,125,054
Net Plant HHV Efficiency (%)	38.7%	37.5%	27.0%	25.5%	39.9%	38.8%	28.7%	27.2%	38.9%	38.0%	27.3%	25.9%
Net Plant HHV Heat Rate (Btu/kWh)	8,813	9,093	12,634	13,361	8,552	8,795	11,898	12,558	8,770	8,975	12,476	13,182
Raw Water Withdrawal, gpm	2,649	2,683	7,642	7,817	2,578	2,597	7,117	7,261	2,393	2,379	7,762	7,996
Raw Water Consumption, gpm	2,093	2,125	5,527	5,456	2,035	2,056	5,141	5,060	1,839	1,828	5,713	5,704
CO_2 Emissions (lb/MMBtu)	215	219	21	22	215	219	21	22	213	219	21	22
CO_2 Emissions (lb/MWh_{gross})	1,786	1,877	222	236	1,737	1,820	211	225	1,775	1,865	220	236
CO_2 Emissions (lb/MWh_{net})	1,892	1,996	271	293	1,836	1,930	255	276	1,866	1,963	265	288
SO_2 Emissions (lb/MMBtu)	0.119	0.132	0.002	0.002	0.119	0.132	0.002	0.002	0.102	0.113	0.002	0.002
SO_2 Emissions (lb/MWh_{gross})	0.990	1.130	0.020	0.020	0.960	1.100	0.020	0.020	0.850	0.970	0.020	0.020
NOx Emissions (lb/MMBtu)	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070
NOx Emissions (lb/MWh_{gross})	0.582	0.599	0.723	0.752	0.566	0.581	0.689	0.716	0.584	0.597	0.723	0.754
PM Emissions (lb/MMBtu)	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
PM Emissions (lb/MWh_{gross})	0.108	0.111	0.134	0.140	0.105	0.108	0.128	0.133	0.108	0.111	0.134	0.140
Hg Emissions (lb/TBtu)	0.597	1.121	0.597	1.121	0.597	1.121	0.597	1.121	0.302	0.482	0.302	0.482
Hg Emissions (lb/MWh_{gross})	4.96E-06	9.59E-06	6.16E-06	1.20E-05	4.83E-06	9.29E-06	5.87E-06	1.15E-05	2.52E-06	4.11E-06	3.12E-06	5.19E-06
COST												
Total Plant Cost (2007$/kW)	1,033,301	1,122,438	1,797,852	1,958,416	1,084,716	1,185,901	1,827,095	1,973,559	1,062,836	1,123,412	1,812,415	1,943,572
Total Overnight Cost (2007$/kW)	2,293	2,489	3,987	4,341	2,405	2,628	4,049	4,372	2,357	2,490	4,018	4,307
Bare Erected Cost	1,530	1,663	2,517	2,750	1,577	1,725	2,530	2,738	1,480	1,563	2,424	2,600
Home Office Expenses	145	157	238	261	149	163	239	259	141	149	230	247
Project Contingency	204	220	406	438	213	231	408	437	210	221	407	435
Process Contingency	0	0	107	112	33	37	144	154	102	110	233	251
Owner's Costs	414	448	718	781	433	472	727	783	425	448	722	773
Total Overnight Cost (2007$x1,000)	1,261,175	1,369,100	2,192,877	2,387,887	1,322,909	1,445,367	2,227,086	2,404,506	1,296,474	1,369,642	2,209,764	2,368,935
Total As Spent Capital (2007$/kW)	2,600	2,823	4,545	4,949	2,742	2,996	4,615	4,984	2,687	2,839	4,580	4,909
COE (mills/kWh, 2007$)[1]	57.8	62.2	107.5	116.4	62.2	67.3	107.7	115.4	61.5	64.6	108.0	115.2
CO_2 TS&M Costs	0.0	0.0	6.0	6.2	0.0	0.0	5.8	6.0	0.0	0.0	5.9	6.1
Fuel Costs	7.8	7.5	11.2	11.0	7.6	7.3	10.6	10.4	7.8	7.4	11.1	10.9
Variable Costs	5.1	6.1	9.3	11.0	5.1	6.1	9.0	10.3	5.3	6.1	9.5	11.0
Fixed Costs	9.0	9.7	14.5	15.7	9.3	10.1	14.7	15.8	9.1	9.5	14.5	15.4
Capital Costs	35.9	39.0	66.5	72.4	40.1	43.9	67.6	73.0	39.3	41.6	67.0	71.9
LCOE (mills/kWh, 2007$)[1]	73.3	78.8	136.3	147.5	78.8	85.3	136.5	146.3	78.0	81.9	136.9	146.0

[1] CF is 85% for PC cases

Exhibit ES-4 Results Summary for NGCC Cases

	NGCC with Advanced F Class			
PERFORMANCE	**Case S31A**	**Case L31A**	**Case S31B**	**Case L31B**
CO_2 Capture	0%	0%	90%	90%
Gross Power Output (kW_e)	522,100	557,000	470,000	501,600
Auxiliary Power Requirement (kW_e)	9,690	10,020	34,940	36,960
Net Power Output (kW_e)	512,410	546,980	435,060	464,640
Fuel Flowrate (lb/hr)	153,559	163,560	153,559	163,560
HHV Thermal Input (kW_{th})	1,014,787	1,080,880	1,014,787	1,080,880
Net Plant HHV Efficiency (%)	50.5%	50.6%	42.9%	43.0%
Net Plant HHV Heat Rate (Btu/kWh)	6,757	6,743	7,959	7,938
Raw Water Withdrawal, gpm	1,084	1,148	3,107	3,309
Raw Water Consumption, gpm	841	890	2,321	2,468
CO_2 Emissions (lb/MMBtu)	118	118	12	12
CO_2 Emissions (lb/MWh_{gross})	784	783	87	87
CO_2 Emissions (lb/MWh_{net})	799	797	94	94
SO_2 Emissions (lb/MMBtu)	Negligible	Negligible	Negligible	Negligible
SO_2 Emissions (lb/MWh_{gross})	Negligible	Negligible	Negligible	Negligible
NOx Emissions (lb/MMBtu)	0.009	0.009	0.009	0.009
NOx Emissions (lb/MWh_{gross})	0.060	0.060	0.067	0.066
PM Emissions (lb/MMBtu)	Negligible	Negligible	Negligible	Negligible
PM Emissions (lb/MWh_{gross})	Negligible	Negligible	Negligible	Negligible
Hg Emissions (lb/TBtu)	Negligible	Negligible	Negligible	Negligible
Hg Emissions (lb/MWh_{gross})	Negligible	Negligible	Negligible	Negligible
COST				
Total Plant Cost (2007\$/kW)	341,350	348,275	572,302	588,738
Total Overnight Cost (2007\$/kW)	817	782	1,607	1,548
Bare Erected Cost	546	521	994	957
Home Office Expenses	46	44	84	81
Project Contingency	74	71	62	61
Process Contingency	0	0	174	168
Owner's Costs	151	145	291	281
Total Overnight Cost (2007\$x1,000)	418,817	427,473	698,949	719,155
Total As Spent Capital (2007\$/kW)	879	840	1,732	1,668
COE (mills/kWh, 2007\$)[1]	64.4	63.6	92.9	91.4
CO_2 TS&M Costs	0.0	0.0	3.4	3.3
Fuel Costs	48.2	48.1	56.7	56.6
Variable Costs	1.4	1.3	2.7	2.6
Fixed Costs	3.4	3.2	6.1	5.9
Capital Costs	11.5	11.0	24.0	23.1
LCOE (mills/kWh, 2007\$)[1]	81.7	80.6	117.8	115.8

[1] CF is 85% NGCC cases

PERFORMANCE

Energy Efficiency

The net plant efficiency (HHV basis) for the Montana site cases is shown in Exhibit ES-5 and for the North Dakota site, in Exhibit ES-6. The primary conclusions that can be drawn are:

- The NGCC with no CO_2 capture has the highest net efficiency of the technologies modeled in this study with an efficiency of 50.6 percent at the North Dakota site, slightly higher than the 50.5 percent efficiency at the higher elevation Montana site.
- The NGCC cases with CO_2 capture results in the highest efficiency (43.0 percent for MT site, 42.9 percent for ND site) among all of the capture technologies.
- The trend for energy efficiency among the IGCC non-capture cases at the MT site is as follows: the dry-fed Shell gasifier (42.0 percent), the lower temperature dry fed TRIG gasifier (39.9 percent), the dry-fed Siemens gasifier without high temperature syngas coolers (37.9 percent), and the slurry-fed, two-stage CoP gasifier (36.7 percent).
- When CO_2 capture is added to the IGCC cases, the efficiency of the different configurations begin to converge, as a larger portion of the auxiliaries is used for the common CO_2 capture and compression processes. The gasifier attributes that contribute to a high efficiency, such as dry feed or high temperature heat recovery with no quench, are negated by the need for shift steam in capture cases. The Montana site cases range from 30.4 percent for CoP to 32.1 percent for Shell, with TRIG at 31.8 percent and Siemens at 30.6 percent overall net plant efficiency.
- The North Dakota site lignite IGCC cases have slightly lower efficiency than the MT (PRB) site counterparts, mainly due to the lower rank coal. The non-capture Shell case decreases from 42.0 to 41.8 percent efficiency, and the Siemens case decreases from 37.9 to 37.6 percent efficiency. The CO_2 capture Shell case decreases from 32.1 to 31.7 percent efficiency, and the Siemens case decreases from 30.6 to 30.0 percent efficiency.
- SC PC without CO_2 capture has an efficiency of 38.7 and 37.5 percent for the Montana and North Dakota cases, respectively. CFB with similar steam conditions follow the same trends, but are slightly more efficient at 38.9 and 38.0 percent efficiency, respectively. As steam conditions become more aggressive, the USC PC cases have even higher efficiencies of 39.9 and 38.8 percent, respectively.
- The relative efficiency penalty for adding CO_2 capture to the IGCC cases is 21.2 percent on average, the relative penalty for combustion cases is 30.3 percent, and the relative penalty for NGCC is 15.1 percent.
- The addition of CO_2 capture to the combustion cases has the highest relative efficiency penalties out of all the cases studied. This is primarily because the low partial pressure of CO_2 in the flue gas (FG) from a combustion plant requires a chemical absorption process rather than physical absorption. For chemical absorption processes, the regeneration requirements are more energy intensive. The relative efficiency impact on a NGCC CO_2 capture configuration is less because of the lower carbon intensity of natural gas relative to coal, which more than offsets the reduced driving force for CO_2 separation due to the lower partial pressure of CO_2 in the flue gas.

Exhibit ES-5 Net Plant Efficiency for Montana Site (HHV Basis)

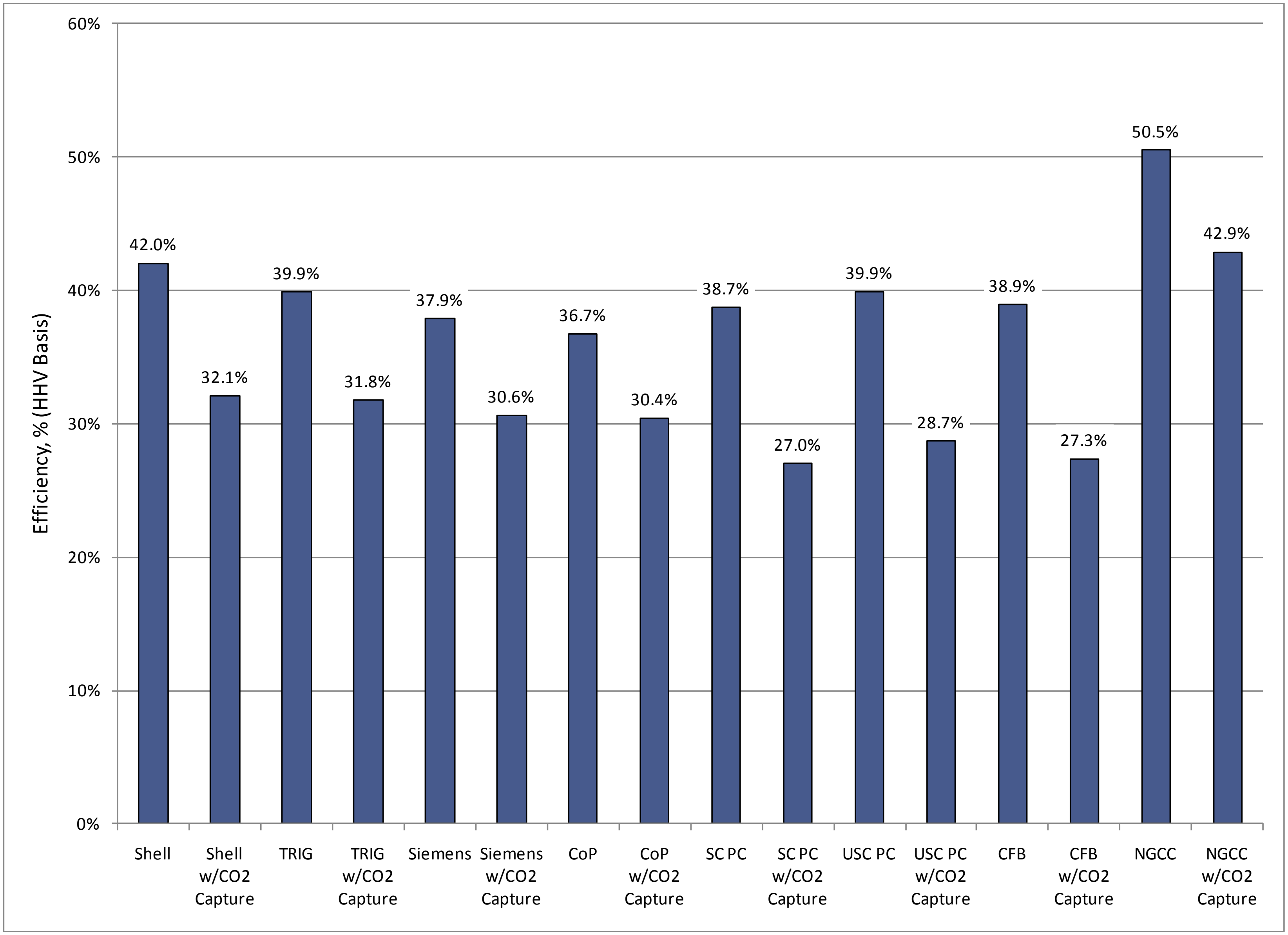
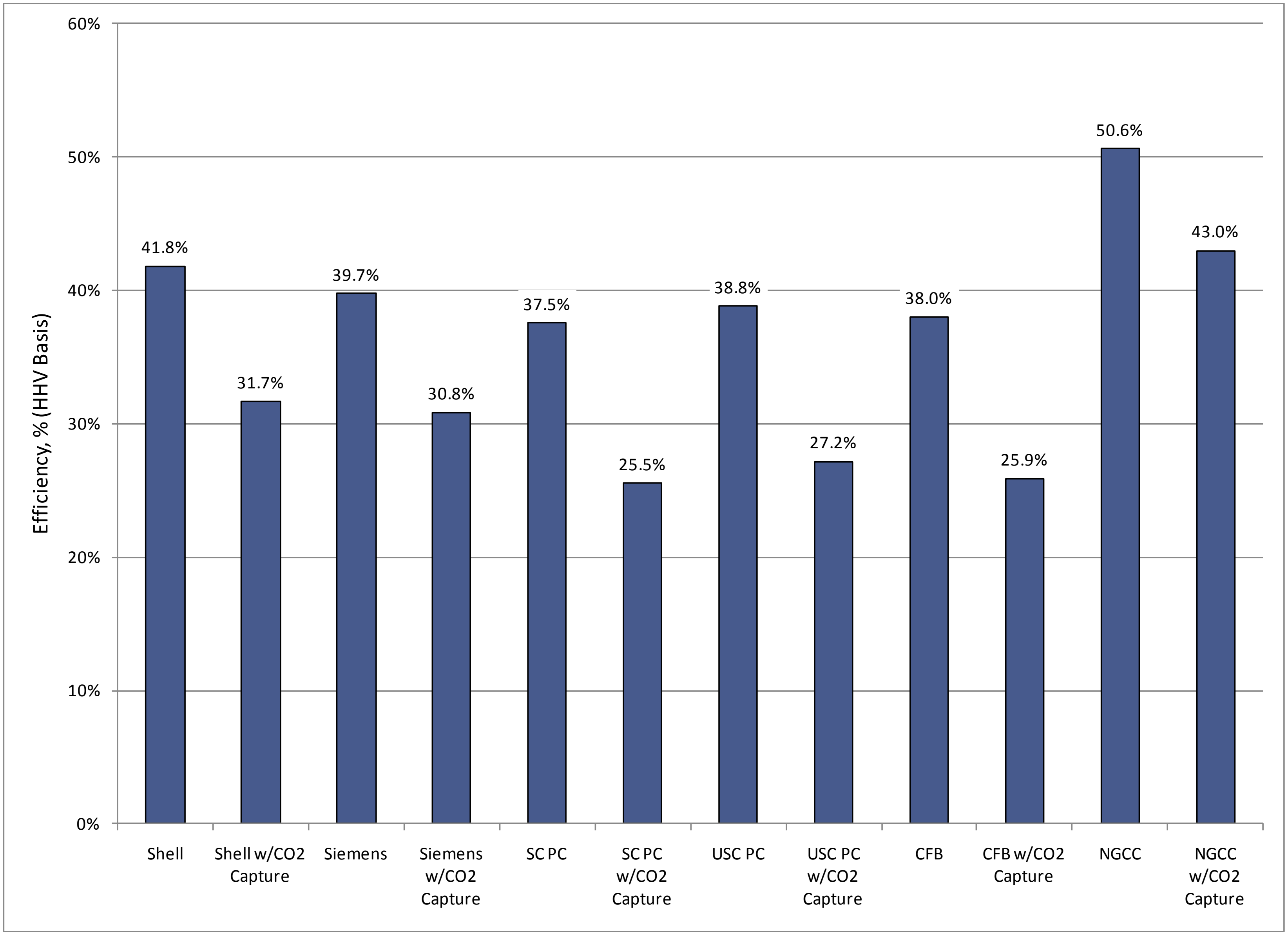


Exhibit ES-6 Net Plant Efficiency for North Dakota Site (HHV Basis)



Water Use

Three water metrics are presented for each technology in Exhibit ES-7 for the Montana site and Exhibit ES-8 for the North Dakota site: raw water withdrawal, process discharge, and raw water consumption. In each of these exhibits, the values are normalized by the net plant output. Raw water withdrawal is the difference between demand and internal recycle. Demand is the amount of water required to satisfy a particular process (cooling tower makeup, flue gas desulfurization [FGD] makeup, etc.) and internal recycle is water available within the process. Raw water withdrawal is the water removed from the ground or diverted from a surface-water source for use in the plant. Raw water consumption is the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source it was withdrawn from. Raw water consumption is the difference between withdrawal and process discharge, and it represents the overall impact of the process on the water source, which in this study is considered to be 50 percent from groundwater (wells) and 50 percent from a municipal source. The largest consumer of raw water in all cases is cooling tower makeup. Since plants located in the Western U.S. need to consider limited water supplies, a parallel wet/dry condenser was chosen for all plant configurations. In a parallel cooling system half of the turbine exhaust steam is condensed in an air-cooled condenser and half in a water-cooled condenser. Other cooling loads, including the Econamine process, are satisfied using cooling water. Cooling water is provided by a mechanical draft, evaporative cooling tower. The primary conclusions that can be drawn are:

- In all cases the primary water consumer is cooling tower makeup, which ranges from 55 to 99 percent of the total raw water consumption.
- Among non-capture cases, NGCC requires the least amount of raw water withdrawal, followed by IGCC and combustion cases (which include all PC and CFB cases, which have similar performance profiles). The relative average normalized raw water consumption for the Montana site cases is 2.2:2.0:1.0 (PC:IGCC:NGCC) and 2.2:1.6:1.0 for the North Dakota cases. The relative results are as expected given the higher steam turbine output in the PC cases, which results in higher condenser duties, higher cooling water flows, and ultimately higher cooling water makeup. The IGCC cases and the NGCC case have comparable steam turbine outputs, but IGCC requires additional water for coal slurry (CoP), syngas quench (Siemens), and slag handling (all cases). No slurry fed gasifiers were included in the North Dakota results.
- Among capture cases, raw water withdrawal requirements increase (relative to non-capture cases) more dramatically for the PC and NGCC cases than for IGCC cases because of the large cooling water demand of the Econamine process, which results in greater cooling water makeup requirements. The relative average normalized raw water consumption for the Montana site CO_2 capture cases is 1.9:1.2:1.0 (PC:IGCC:NGCC) and 2.2:1.3:1.0 for the North Dakota cases.
- CO_2 capture increases the average raw water consumption for all technologies, but the increase is lowest for the IGCC cases. The average normalized raw water consumption for the IGCC cases increases by about 98 percent for the Montana cases and 161 percent for the North Dakota cases due primarily to the need for additional water in the syngas to accomplish the WGS reaction. With the addition of CO_2 capture, PC normalized raw water consumption increases by 174 percent for the Montana cases and 170 percent for

the North Dakota cases. The NGCC cases' water consumption increases by approximately 225 percent for both site locations. The large cooling water demand of the Econamine process drives this substantial increase for the PC and NGCC technologies.

Exhibit ES-7 Raw Water Withdrawal and Consumption for Montana Site

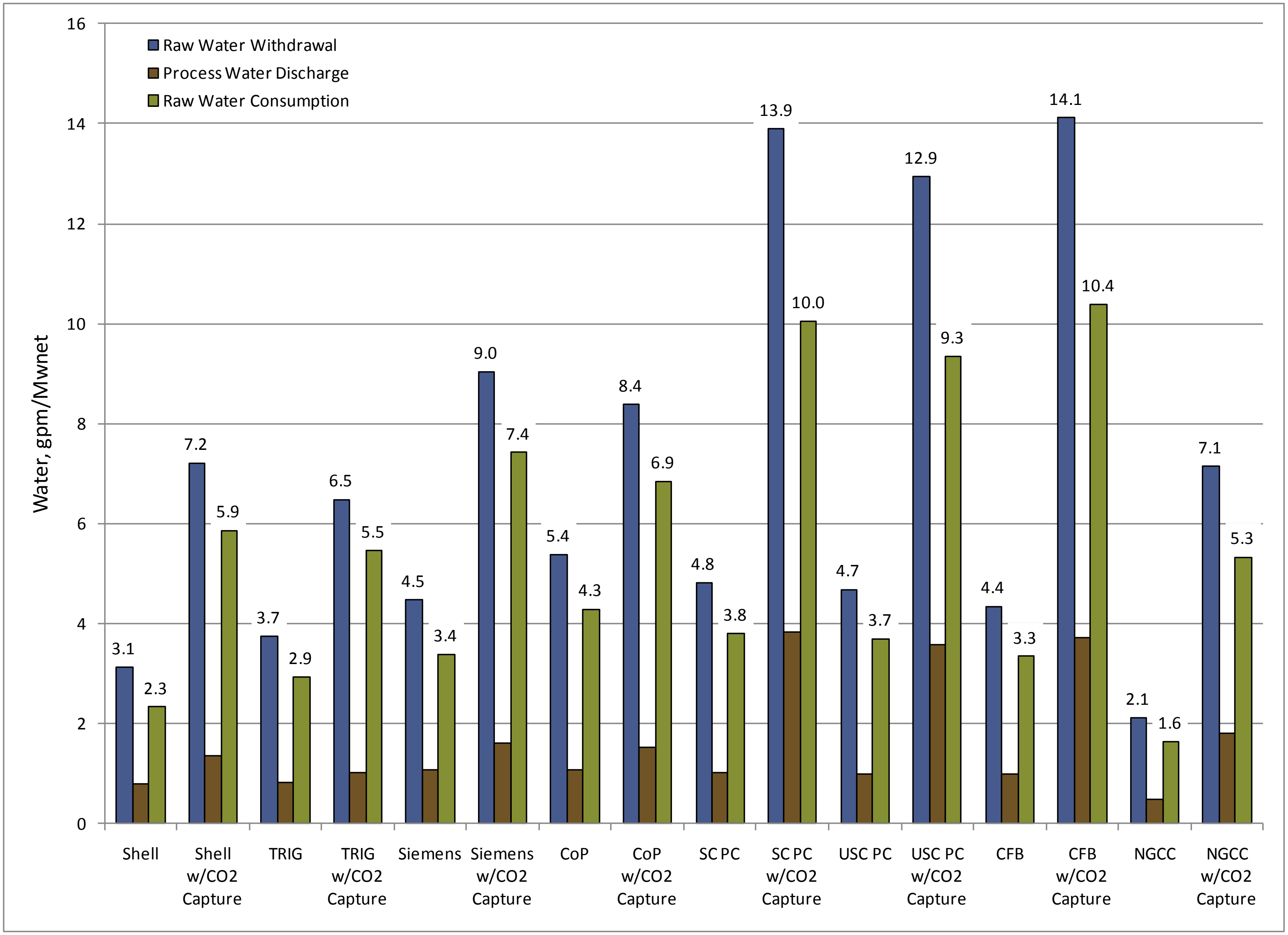
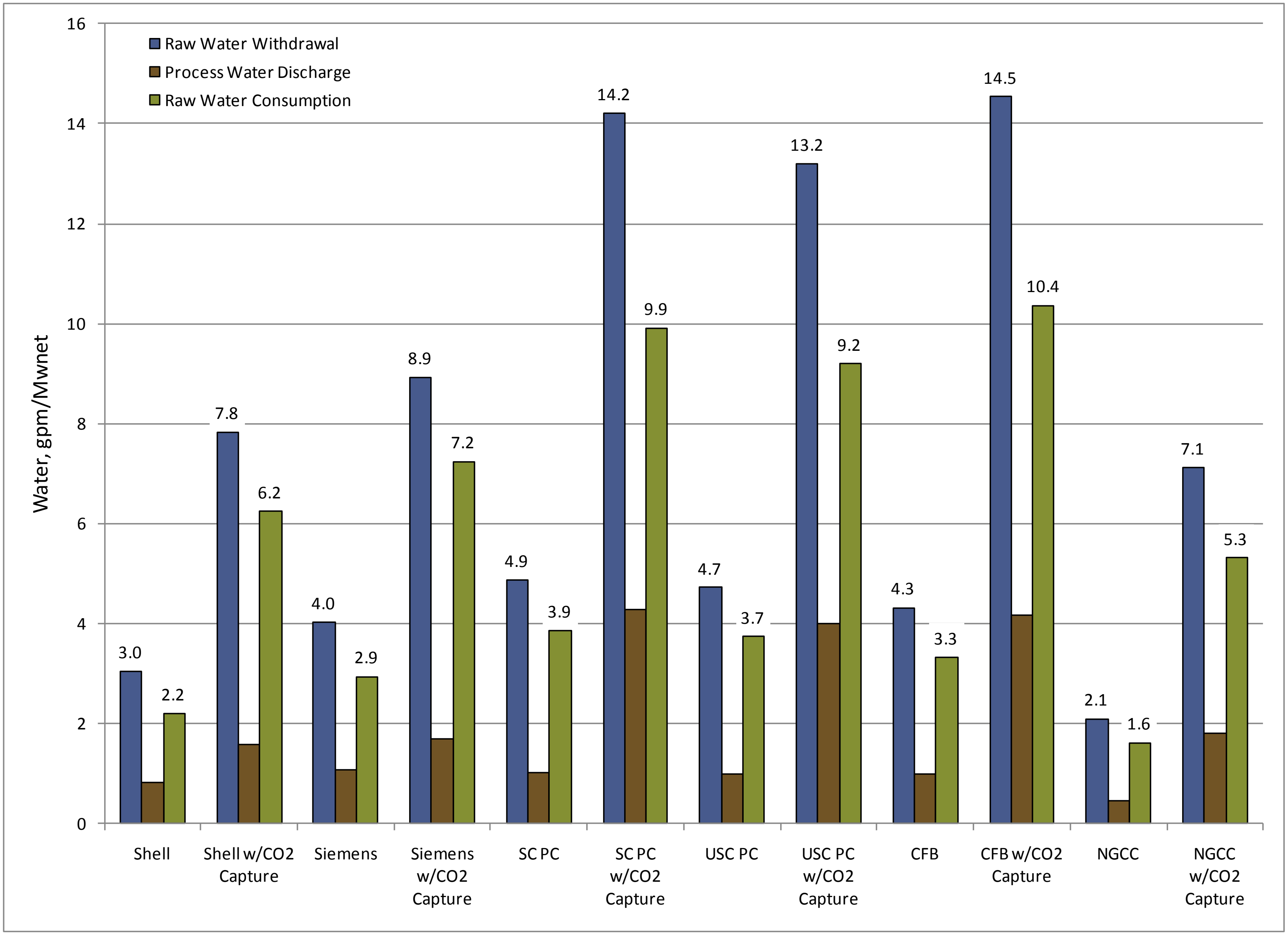


Exhibit ES-8 Raw Water Withdrawal and Consumption for North Dakota Site



COST RESULTS

Total Overnight Cost

The Total Overnight Cost (TOC) for each plant was calculated by adding owner's costs to the Total Plant Cost (TPC). The TPC for each technology was determined through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. TPC includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Escalation and interest on debt during the capital expenditure period were estimated and added to the TOC to provide the Total As-Spent Capital (TASC).

The cost estimates carry an accuracy of -15%/+30%, consistent with a "feasibility study" level of design engineering. The value of the study lies not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.

Project contingencies were added to the Engineering/Procurement/Construction Management (EPCM) capital accounts to cover project uncertainty and the cost of any additional equipment that would result from a detailed design. The contingencies represent costs that are expected to occur. Each bare erected cost (BEC) account was evaluated against the level of estimate detail and field experience to determine project contingency.

Process contingency was added to cost account items that were deemed to be first-of-a-kind (FOAK) or posed significant risk due to lack of operating experience. The cost accounts that received a process contingency include:

- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases – next-generation commercial offering and integration with the power island.
- Two Stage Selexol – 20 percent on all IGCC capture cases – lack of operating experience at commercial scale in IGCC service.
- Mercury Removal – 5 percent on all IGCC cases – minimal commercial scale experience in IGCC applications.
- CO_2 Removal System – 20 percent on all PC/NGCC capture cases - post-combustion process unproven at commercial scale for power plant applications.
- Combustion Turbine-Generator (CTG) – 5 percent on all IGCC non-capture cases – syngas firing and air separation unit (ASU) integration; 10 percent on all IGCC capture cases – high hydrogen firing.
- Instrumentation and Controls – 5 percent on all IGCC accounts and 5 percent on the PC and NGCC capture cases – integration issues.

The normalized components of TOC and overall TASC are shown for each technology in Exhibit ES-9 for the Montana site and Exhibit ES-10 for the North Dakota site. TOC is expressed in June 2007 dollars. TASC is expressed in mixed-year 2007 to 2011 year dollars for coal plants and 2007 to 2009 mixed-year dollars for NGCC. The following conclusions can be drawn:

- Among the non-capture cases at the Montana site, NGCC has the lowest TOC at \$817/kW followed by the combustion cases with an average cost of \$2,352/kW and IGCC with an average cost of \$2,935/kW. At the North Dakota site, NGCC has the lowest TOC at \$782/kW (which is lower than at the Montana site due to increased output) followed by PC with an average cost of \$2,536/kW and IGCC with an average cost of \$3,166/kW, using the lower rank coal.
- Among the capture cases at the Montana site, NGCC has the lowest TOC of \$1,607kW followed by PC with an average cost of \$4,018/kW and IGCC with an average cost of \$4,028/kW. At the North Dakota site, NGCC again has the lowest TOC, \$1,548/kW, followed by PC with an average cost of \$4,340/kW and IGCC with an average cost of \$4,404/kW.
- The average non-capture IGCC cost is 25 percent greater than the average PC cost. The process contingency for the IGCC non-capture cases ranges from \$56-83/kW, while there is minimal process contingency for the SC PC and NGCC non-capture cases. The differential between IGCC and PC is reduced to 22 percent when the IGCC process contingency is eliminated.
- The average CO_2 capture IGCC cost is roughly equivalent to or slightly greater than the average PC cost. The process contingencies are universally higher for the more complex, less commercially mature CO_2 capture processes and plant configurations: the IGCC capture cases process contingency ranges from \$135-164/kW, the PC cases from \$107-154/kW, CFB cases \$233-251/kW, and \$168-174/kW for the NGCC cases.

Exhibit ES-9 Plant Capital Costs for Montana Site

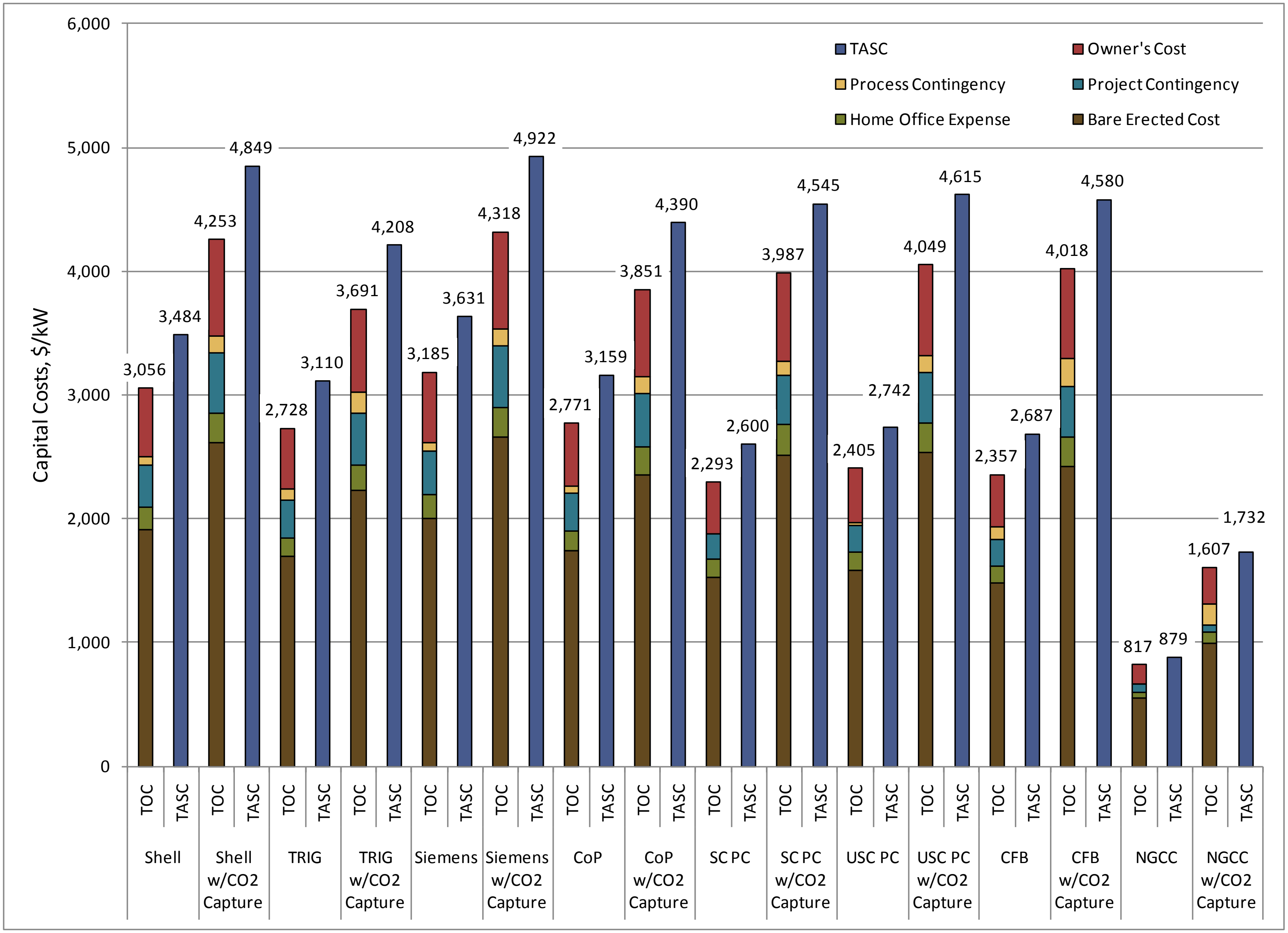
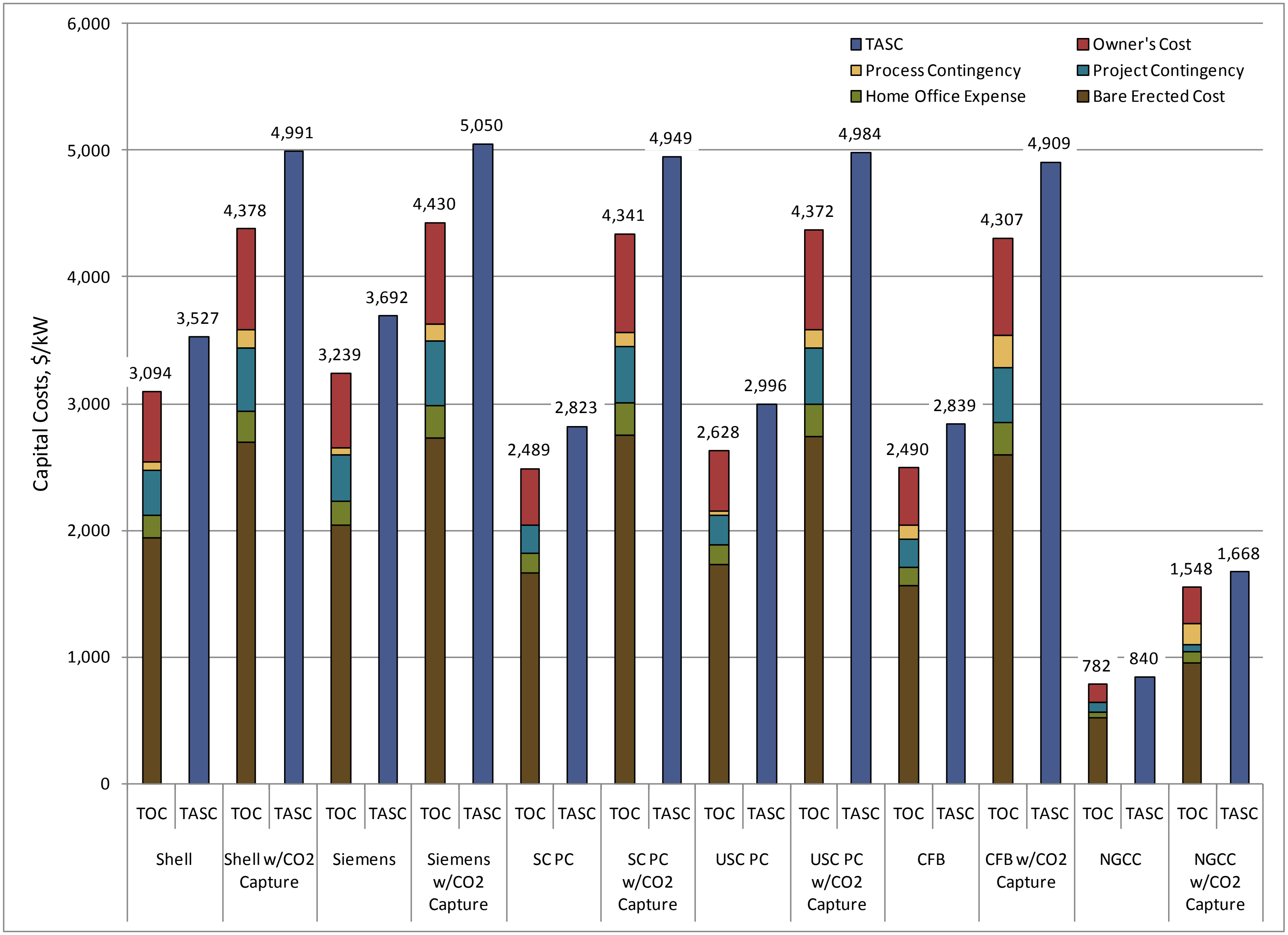


Exhibit ES-10 Plant Capital Costs for North Dakota Site



Cost of Electricity

The cost metric used in this study is the COE, which is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, *assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant*. To calculate the COE, the Power Systems Financial Model (PSFM) [4] was used to determine a "base-year" (2007) COE that, when escalated at an assumed nominal annual general inflation rate of 3 percent[1], provided the stipulated internal rate of return on equity over the entire economic analysis period (capital expenditure period plus thirty years of operation). The first year capital charge factor (CCF) shown in Exhibit ES-11, which was derived using the PSFM, can also be used to calculate COE using the simplified equation below.

$$COE = \frac{\begin{matrix} first\ year \\ capital\ charge \end{matrix} + \begin{matrix} first\ year \\ fixed\ operating \\ costs \end{matrix} + \begin{matrix} first\ year \\ variable\ operating \\ costs \end{matrix}}{\begin{matrix} annual\ net\ megawatt\ hours \\ of\ power\ generated \end{matrix}}$$

$$COE = \frac{(CCF)(TOC) + OC_{FIX} + (CF)(OC_{VAR})}{(CF)(MWH)}$$

where:

COE =	revenue received by the generator ($/MWh, equivalent to mills/kWh) during the power plant's first year of operation (*but expressed in base-year dollars*), assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant.
CCF =	capital charge factor taken from Exhibit ES-11 that matches the applicable finance structure and capital expenditure period
TOC =	total overnight capital, expressed in *base-year dollars*
OC_{FIX} =	the sum of all fixed annual operating costs, *expressed in base-year dollars*
OC_{VAR} =	the sum of all variable annual operating costs, including fuel at 100 percent capacity factor, *expressed in base-year dollars*
CF =	plant capacity factor, assumed to be constant over the operational period
MWH =	annual net megawatt-hours of power generated at 100 percent capacity factor

[1] This nominal escalation rate is equal to the average annual inflation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods. This index was used instead of the Producer Price Index for the Electric Power Generation Industry because the Electric Power Index only dates back to December 2003 and the Producer Price Index is considered the "headline" index for all of the various Producer Price Indices.

The project financial structure varies depending on the type of project (high risk or low risk) and the length of the capital expenditure period (3 year or 5 year). All cases were assumed to be undertaken at investor owned utilities (IOUs). High risk projects are those in which commercial scale operating experience is limited. The IGCC and SC CFB cases (with and without CO_2 capture) and the PC and NGCC cases with CO_2 capture were considered to be high risk. The non-capture PC and NGCC cases were considered to be low risk. Coal based cases were assumed to have a 5 year capital expenditure period and natural gas cases a 3 year period. The current-dollar, 30-year levelized cost of electricity (LCOE) was also calculated and is in the results summary, but the primary metric used in the balance of this study is COE.

Exhibit ES-11 Economic Parameters Used to Calculate COE

	High Risk (5 year capital expenditure period)	**Low Risk (5 year capital expenditure period)**	**High Risk (3 year capital expenditure period)**	**Low Risk (3 year capital expenditure period)**
First Year Capital Charge Factor	0.1243	0.1165	0.1111	0.1048

Commodity prices fluctuate over time based on overall economic activity and general supply and demand curves. While the cost basis for this study is June 2007, many price indices had similar values in January 2010 compared to June 2007. For example, the Chemical Engineering Plant Cost Index was 532.7 in June 2007 and 532.9 in January 2010, and the Gross Domestic Product Chain-type Price Index was 106.7 on July 1, 2007 and 110.0 on January 1, 2010. Hence the June 2007 dollar cost base used in this study is expected to also be representative of January 2010 costs.

The COE results are shown in Exhibit ES-12 for the Montana site cases and Exhibit ES-13 for the North Dakota site cases with the capital cost, fixed operating cost, variable operating cost, and fuel cost shown individually. In the capture cases, the CO_2 transport, storage, and monitoring (TS&M) costs are also shown as a separate bar segment. The following conclusions can be drawn:

- In non-capture cases, at the Montana site, the combustion cases have the lowest COE (average 60.5 mills/kWh), followed by NGCC (64.4 mills/kWh) and IGCC (average 80.8 mills/kWh). At the North Dakota site, the SC PC plant has the lowest COE (61.5 mills/kWh, all combustion cases average 64.7 mills/kWh), followed by NGCC (63.6 mills/kWh) and IGCC (average 85.4 mills/kWh).
- In capture cases, at the Montana site, NGCC plants have the lowest COE (92.9 mills/kWh), followed by the combustion cases (average 107.7 mills/kWh) and IGCC (average 114.7 mills/kWh), although the TRIG case (105.2 mills/kWh), with an 83% CO_2 capture efficiency, is less expensive than the PC technologies. At the North Dakota site, NGCC plants have the lowest COE (91.4 mills/kWh), followed by the combustion cases (average 115.6 mills/kWh) and IGCC (average 122.8 mills/kWh).

- The capital cost component of COE is between 61 and 66 percent in all IGCC and PC cases. It represents only 18 percent of COE in the NGCC non-capture cases and 26 percent in the CO_2 capture cases mainly because NGCC cases use a cleaner and less carbon intensive but more expensive fuel.
- The fuel component of COE ranges from 7-14 percent for the PC and IGCC cases. The fuel component is 75 percent of the total in the NGCC non-capture cases and 61 percent in the CO_2 capture cases.
- CO_2 TS&M is estimated to add 3 to 6 mills/kWh to the COE, which is less than 6 percent of the total for all capture cases.

Exhibit ES-12 COE by Cost Component for Montana Site

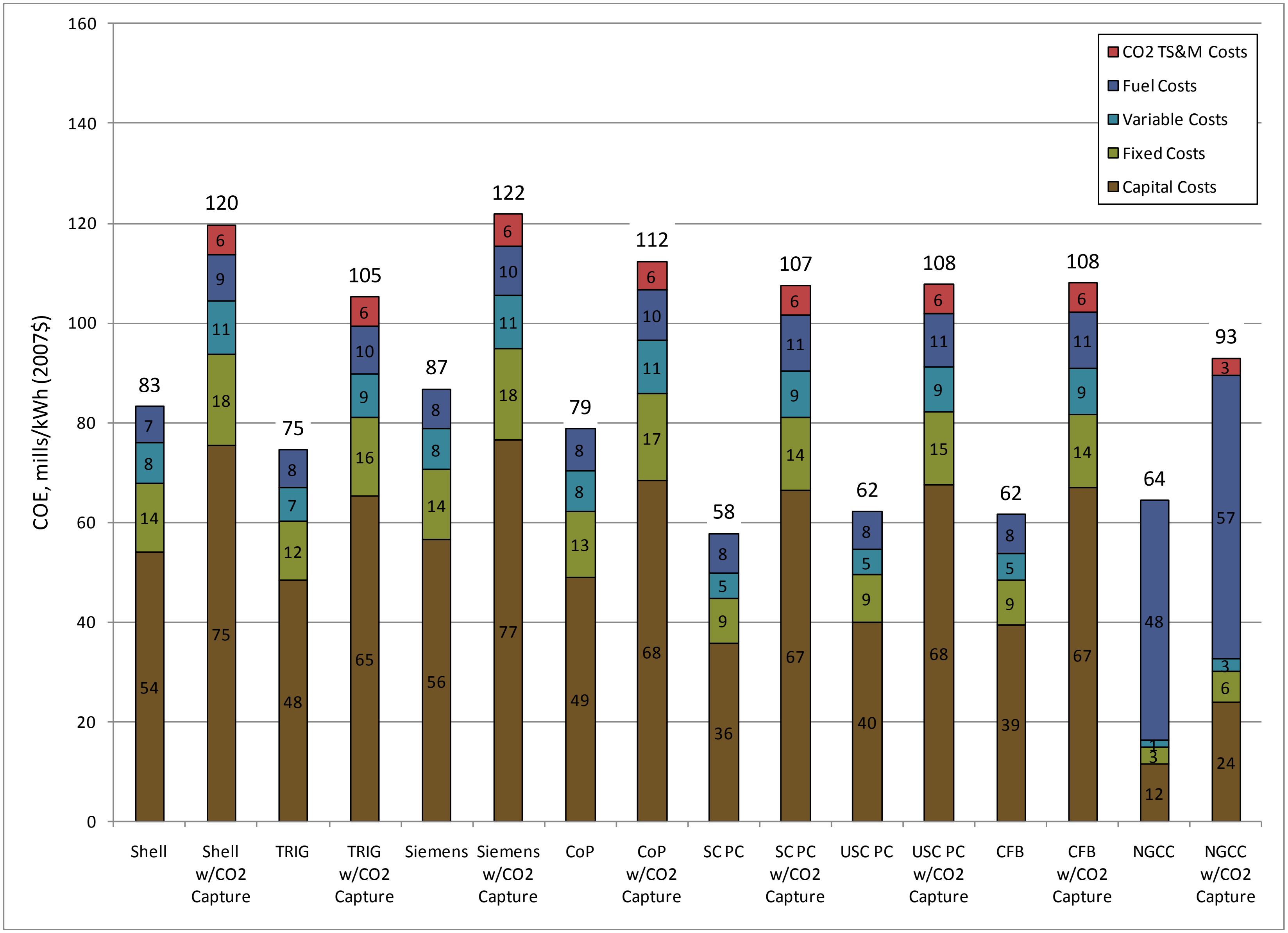
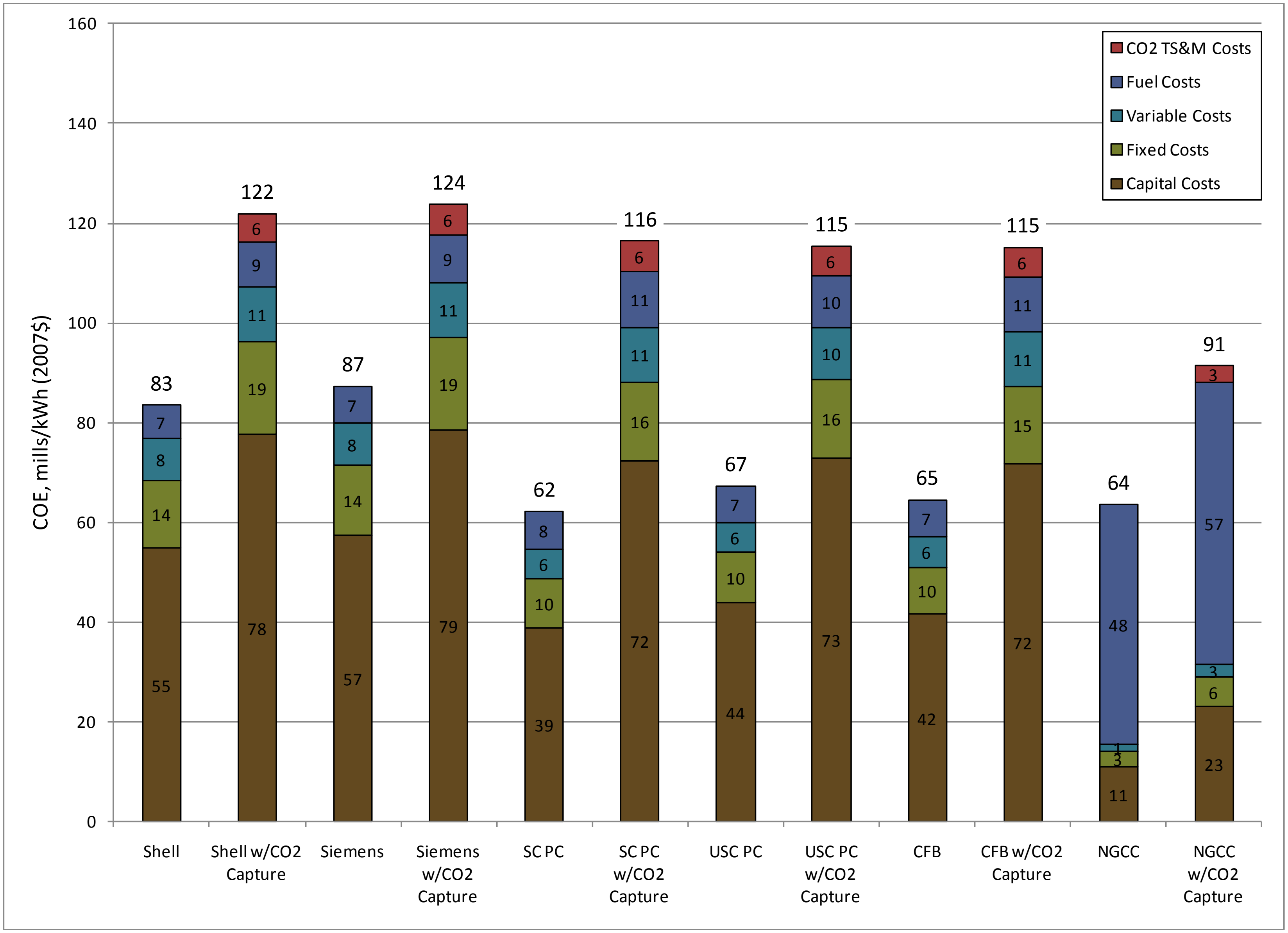


Exhibit ES-13 COE by Cost Component for North Dakota Site



Cost of CO_2 Avoided

The first year cost of CO_2 avoided was calculated as illustrated in Equation ES-1:

$$Avoided\ Cost = \frac{\{COE_{with\ removal} - COE_{reference}\}\ \$/MWh}{\{CO_2\ Emissions_{reference} - CO_2\ Emissions_{with\ removal}\}\ tons/MWh} \qquad \text{(ES-1)}$$

The COE with CO_2 removal includes the costs of capture and compression as well as TS&M costs. The resulting avoided costs are shown in Exhibit ES-14 for the Montana site cases and Exhibit ES-15 for the North Dakota site cases for each of the technologies modeled. The avoided costs for each capture case are calculated using the analogous non-capture plant as the reference and again with SC PC without CO_2 capture as the reference. The following conclusions can be drawn:

- CO_2 avoided costs for IGCC plants, using analogous non-capture plants as reference, are substantially less than for PC and NGCC because the IGCC CO_2 removal is accomplished prior to combustion and at elevated pressure using physical absorption. This metric can be considered an intrinsic property to the technology or configuration gauging the ease of configuring the technology to capture CO_2.
- The CO_2 avoided costs for NGCC plants, using analogous non-capture as reference, are high in part because the NGCC non-capture configuration already emits a very low amount of carbon. Consequently, the removal cost for NGCC plants is normalized by a smaller amount of CO_2 being captured.
- CO_2 avoided costs for NGCC plants without capture, using SC PC as reference, are substantially lower than all the other technologies. The inherently low carbon intensity of the fuel makes even the non-capture NGCC configuration emit almost 60% less CO_2 than the reference SC PC plant, making it a cost effective option for reducing or offsetting smaller amounts of CO_2 emissions. This metric can be used to assess the impact of building NGCC plants instead of coal plants.

Exhibit ES-14 First Year CO_2 Avoided Costs for Montana Site

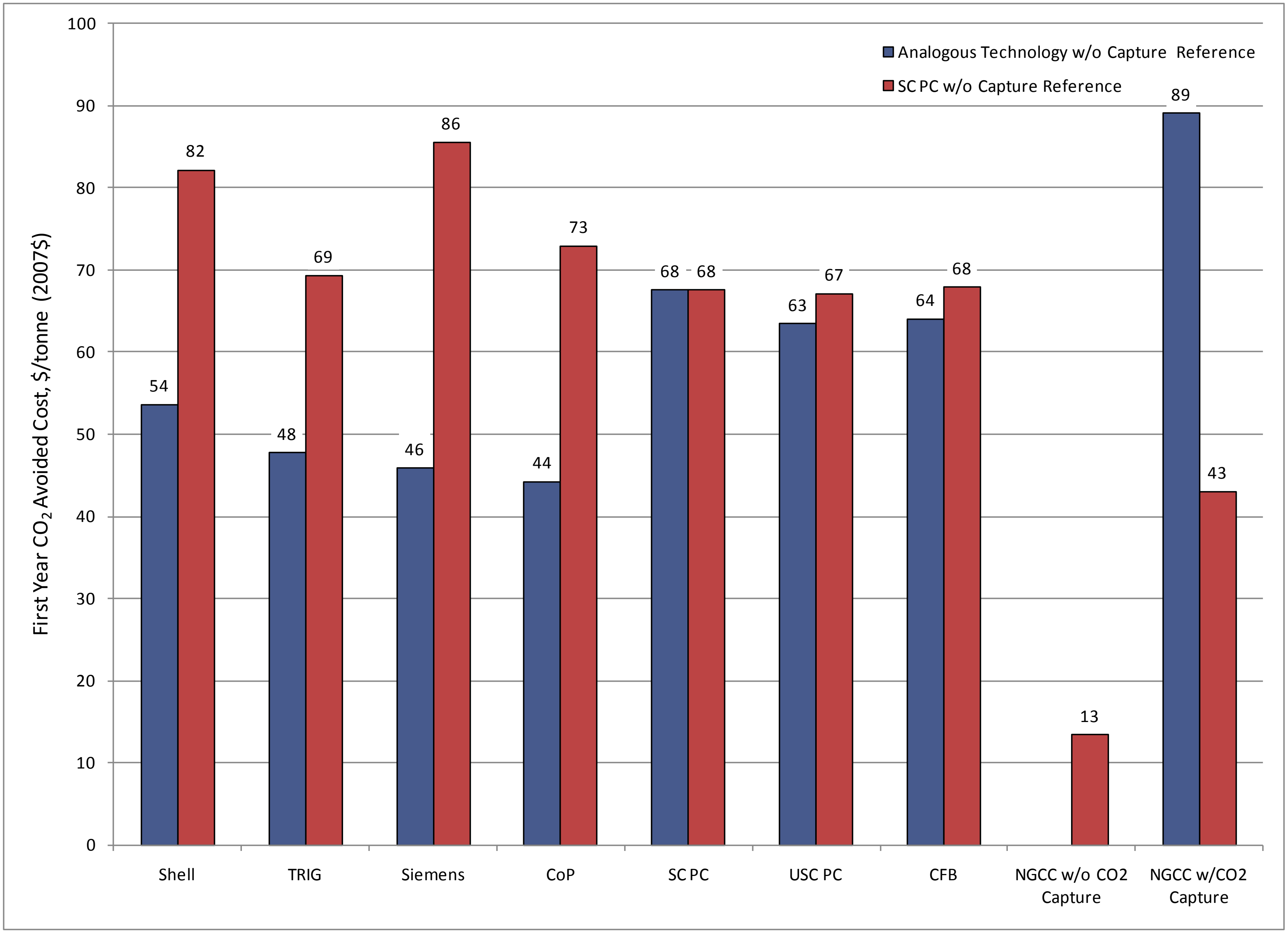
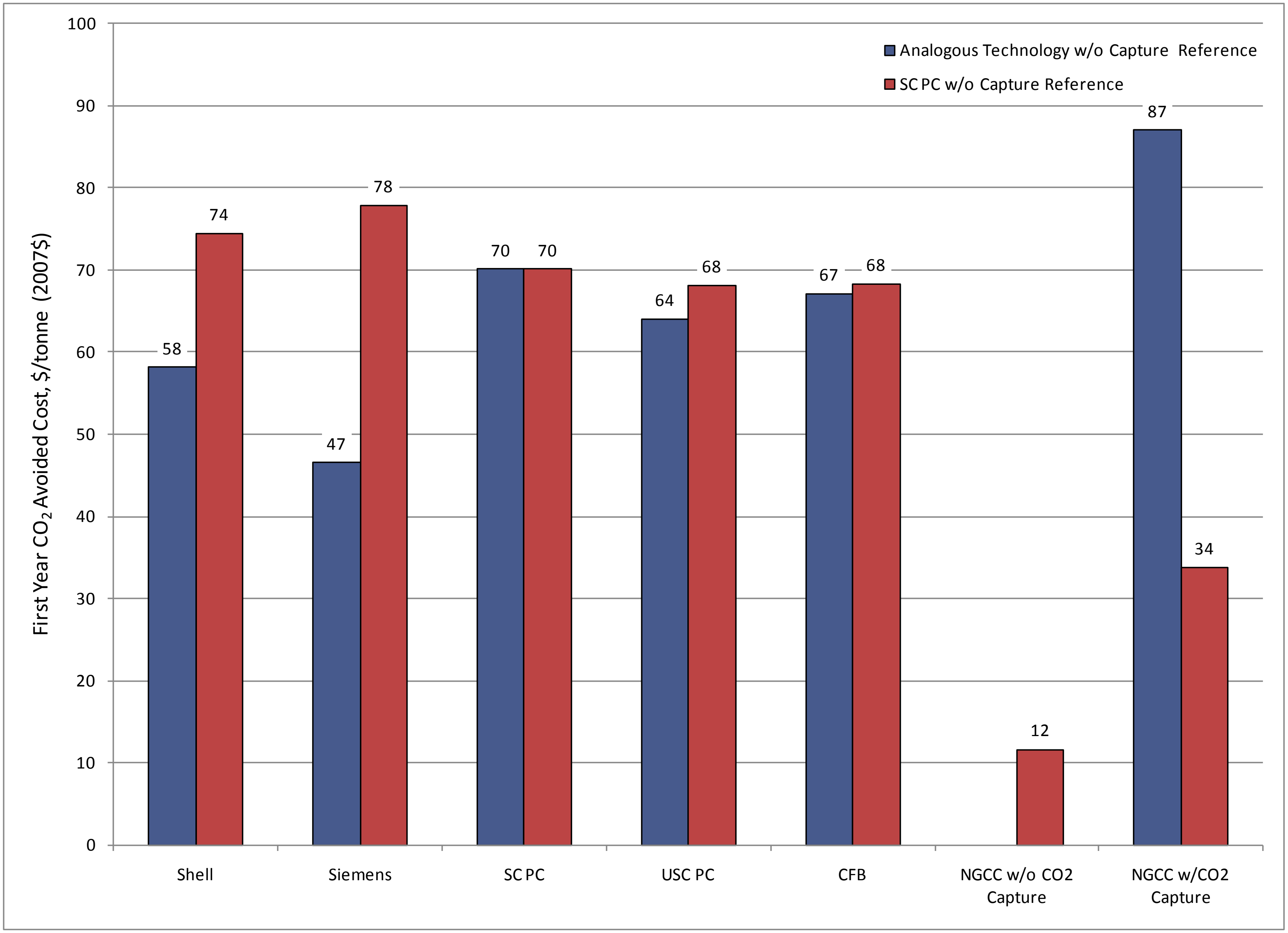


Exhibit ES-15 First Year CO_2 Avoided Costs for North Dakota Site



Fuel Cost Sensitivity

The COE sensitivity to fuel cost for the Montana site cases is presented in Exhibit ES-16 and in Exhibit ES-17 for the North Dakota site cases. The solid line is the COE of NGCC as a function of natural gas cost, the higher green line representing the CO_2 capture case and the lower blue line representing the non-capture case. For comparison, the lowest COE configuration was selected to represent each technology type: TRIG for PRB IGCC cases, Shell for Lignite IGCC cases, and SC PC for the PC cases. The points on the line represent the natural gas cost that would be required to make the COE of NGCC equal to the other technologies at a varied coal costs. For each coal type, associated with each site location, a range of coal price scenarios are plotted representing the base coal cost ± 25 percent. This translates to data points at [$0.67, $0.89, and $1.11/MMBtu] for the Montana PRB coal costs and [$0.62, $0.83, and $1.03/MMBtu] for the North Dakota lignite coal costs. As an example, at a PRB coal cost of $0.67/MMBtu (25% less than the base cost), the non-capture IGCC becomes competitive with NGCC at a natural gas price of $7.69/MMBtu resulting in a COE of 102.8 mills/kWh.

At higher elevations, PC cases become more attractive, in part because there is no combustion turbine and thus no derate due to lower ambient pressures. For the non-capture scenario, the SC PC cases are the most cost competitive, requiring a natural gas price of $5.92/MMBtu for NGCC to generate power below the Montana PRB SC PC electricity cost of 57.8 mills/kWh assuming the base coal cost. For the lower elevation North Dakota site, NGCC becomes competitive at $6.36/MMBtu, resulting in a COE of 62.2 mills/kWh.

For the CO_2 capture configurations using the base costs, NGCC is the lowest cost option due to the low capital cost component of the COE. For the CO_2 capture configurations at the Montana site, the compact, high efficiency TRIG IGCC case results in a lower cost of electricity than the SC PC case, and beats the NGCC electrical generation cost when natural gas is above $7.97, compared to the base case PRB costs. The Montana PRB CO_2 capture SC PC case requires a natural gas price of $8.23/MMBtu to be competitive with the NGCC CO_2 capture case.

Exhibit ES-16 Sensitivity to Fuel Costs for Montana Site

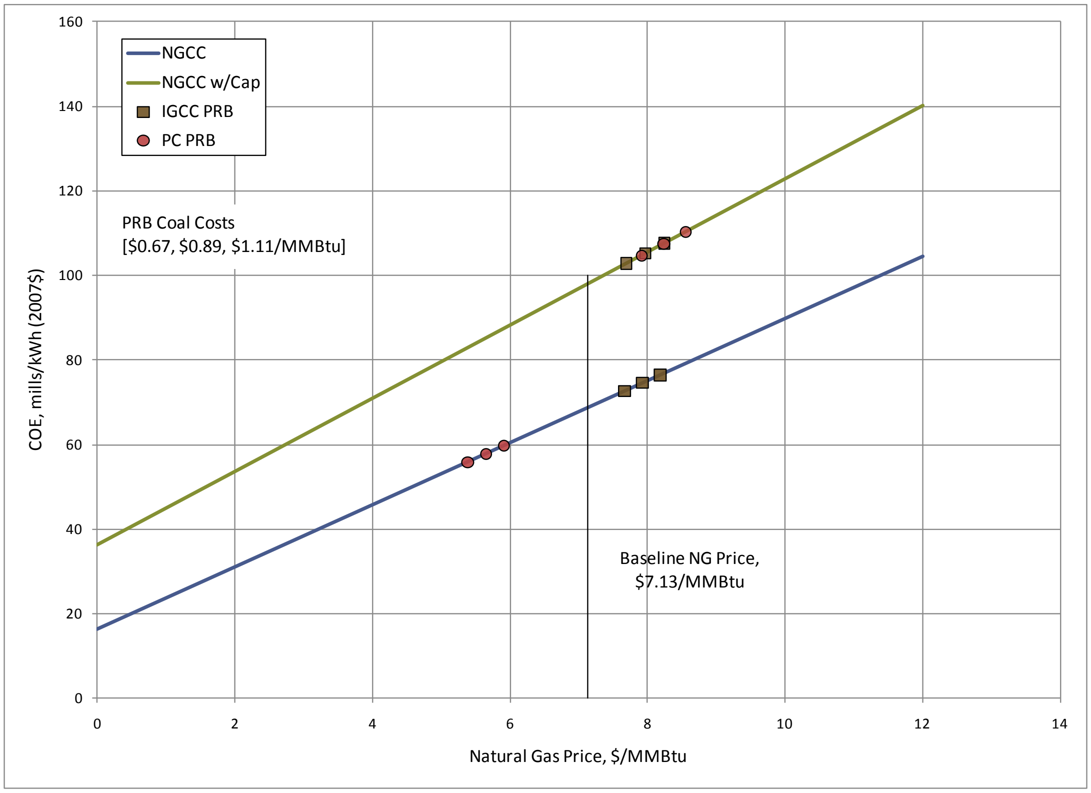
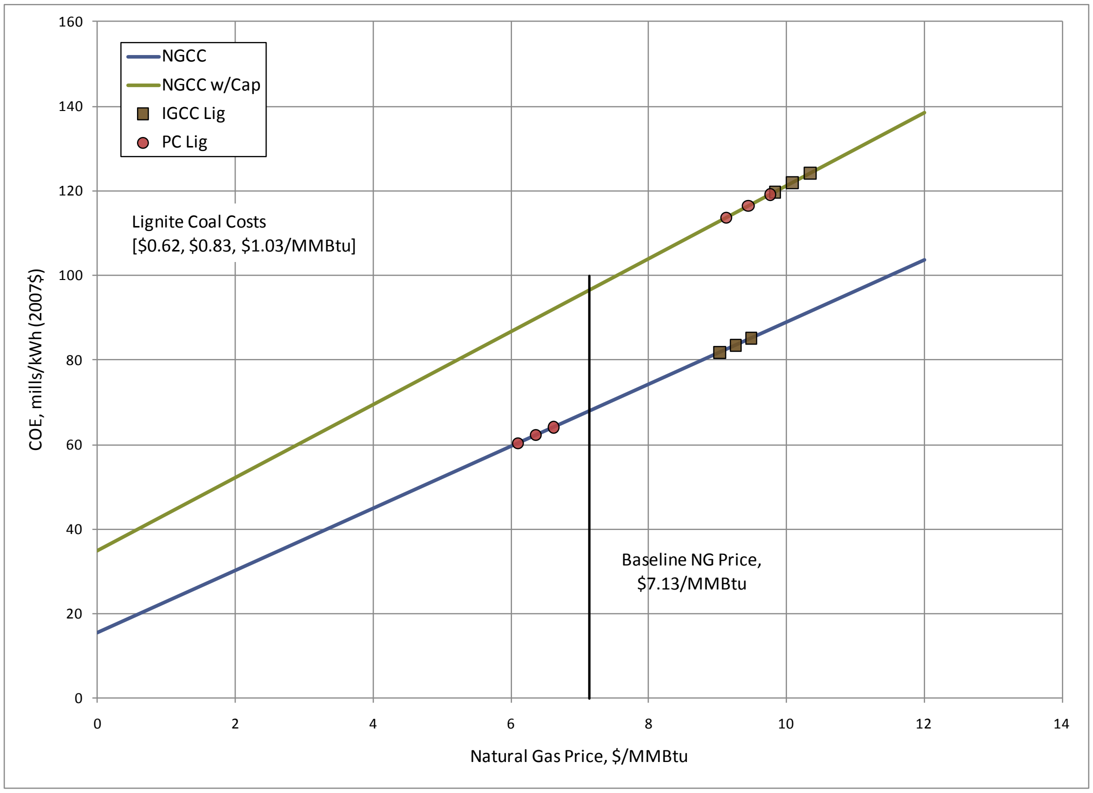


Exhibit ES-17 Sensitivity to Fuel Costs for North Dakota Site



Capacity Factor Sensitivity

The sensitivity of COE to CF is shown for the Montana site cases in Exhibit ES-18 and the North Dakota site cases in Exhibit ES-19. The CF is plotted from 30 to 90 percent. Select cases were chosen to represent the general characteristics of each technology type and configuration and to facilitate comparison between cases. The baseline CF is 80 percent for IGCC cases with no spare gasifier and is 85 percent for PC and NGCC cases. The curves for the IGCC cases assume that the CF could be extended to 90 percent with no spare gasifier. Similarly, the PC and NGCC curves assume that the CF could reach 90 percent with no additional capital equipment.

Technologies with high capital cost (PC and IGCC with CO_2 capture) show a greater increase in COE with decreased CF. Conversely, NGCC with no CO_2 capture is relatively flat because the COE is dominated by fuel costs, which decrease as the CF decreases. Conclusions that can be drawn from this sensitivity include:

- For the Montana site, at a CF below 70 percent, NGCC has the lowest COE out of the non-capture cases. Above this threshold, the TRIG IGCC configuration has the lowest COE.
- For the North Dakota site, at a CF below 85 percent, NGCC has the lowest COE out of the non-capture cases. Above this threshold, the SC PC configuration has the lowest COE.
- NGCC with CO_2 capture is the most attractive CO_2 capture option and can be even less expensive than some of the non-capture configurations, depending on the CF. At a CF below 40 percent, the NGCC CO_2 capture cases become just as costly as the IGCC non-capture running at the base load (80 percent CF) further illustrating the relatively small impact of CF on NGCC COE.

Exhibit ES-18 Sensitivity to Capacity Factor for Montana Site

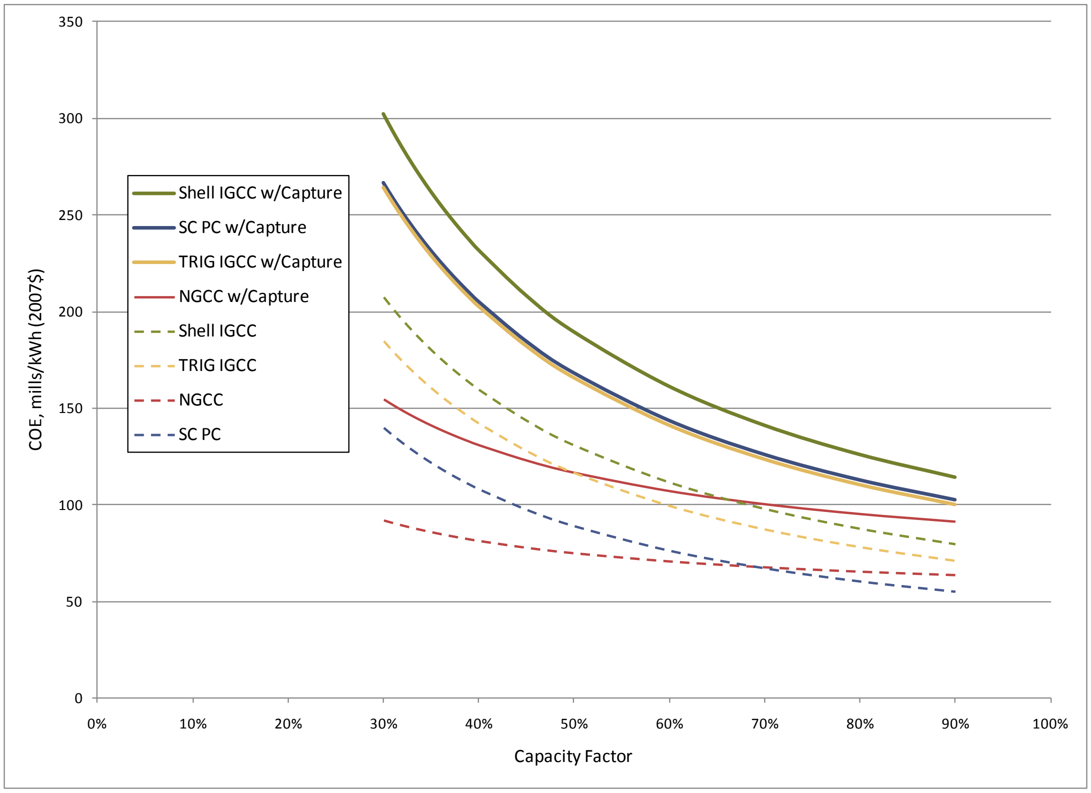
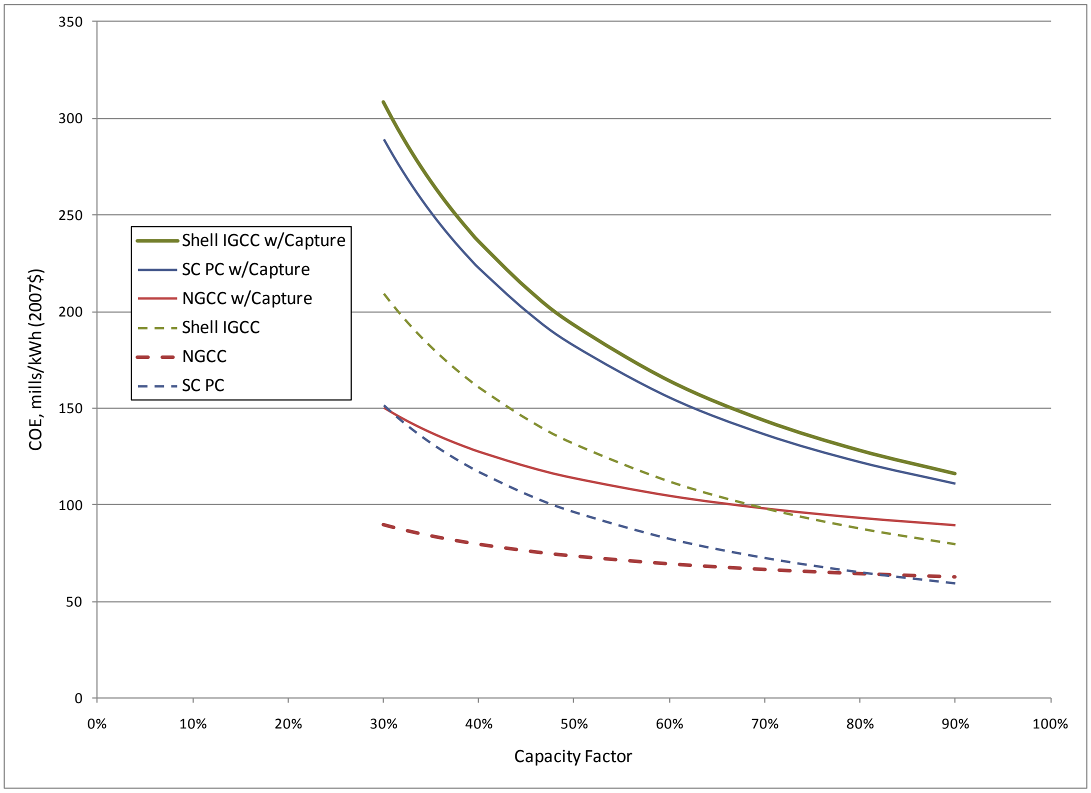


Exhibit ES-19 Sensitivity to Capacity Factor for North Dakota Site



__Combined NGCC Capacity Factor and Natural Gas Price Parity__

A plot combining the CF and fuel cost sensitivities for NGCC plants shows unique characteristics for this low capital cost, high fuel cost generating option, compared to the other options. Due to the high fuel cost, an NGCC plant may not be dispatched whenever the plant is available, which would lower the real world capacity factor. A parametric graph of the breakeven point for selected coal technologies show the required capacity factor and natural gas price, when the indicated coal technology (running at the baseline capacity factor) will have a lower COE than the analogous NGCC case at the same site location. A comparison of the non-capture cases is shown in Exhibit ES-20. The CO_2 capture cases are compared, using a \$67/tonne CO_2 emission price, to CO_2 Capture NGCC in Exhibit ES-21 and to non-capture NGCC in Exhibit ES-22. This CO_2 emission price shifts the COE breakeven lines up and to the left and corresponds to the breakeven point where the coal technologies have the lowest COE when adding CO_2 capture rather than paying for uncontrolled emissions. An analysis on the effects of CO_2 emissions prices are discussed in the CO_2 Emissions section.

Exhibit ES-20 Non-Capture Sensitivity to NGCC CF and NG Price

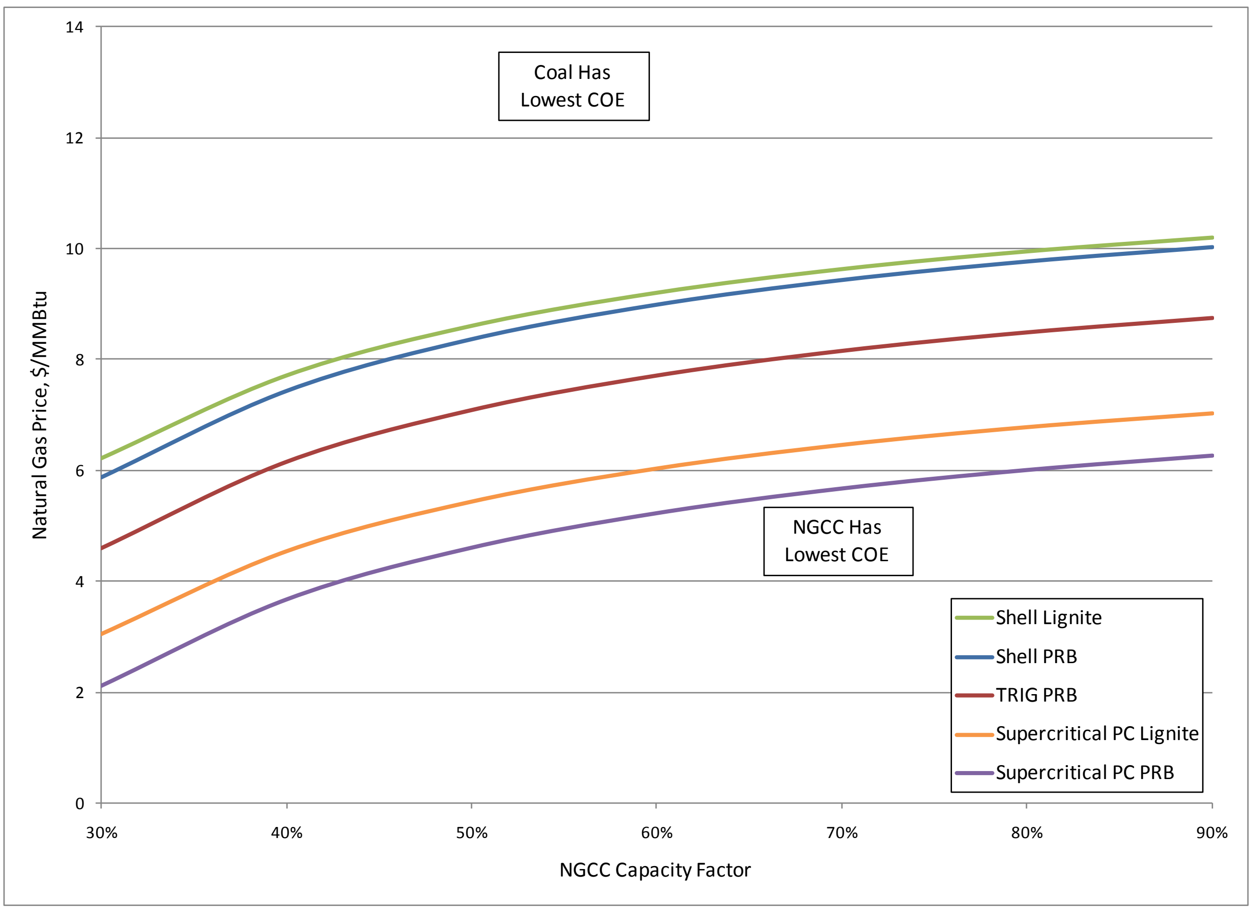


Exhibit ES-21 CCS Sensitivity to CO_2 Capture NGCC CF and NG Price with \$67/tonne CO_2 Emission Price

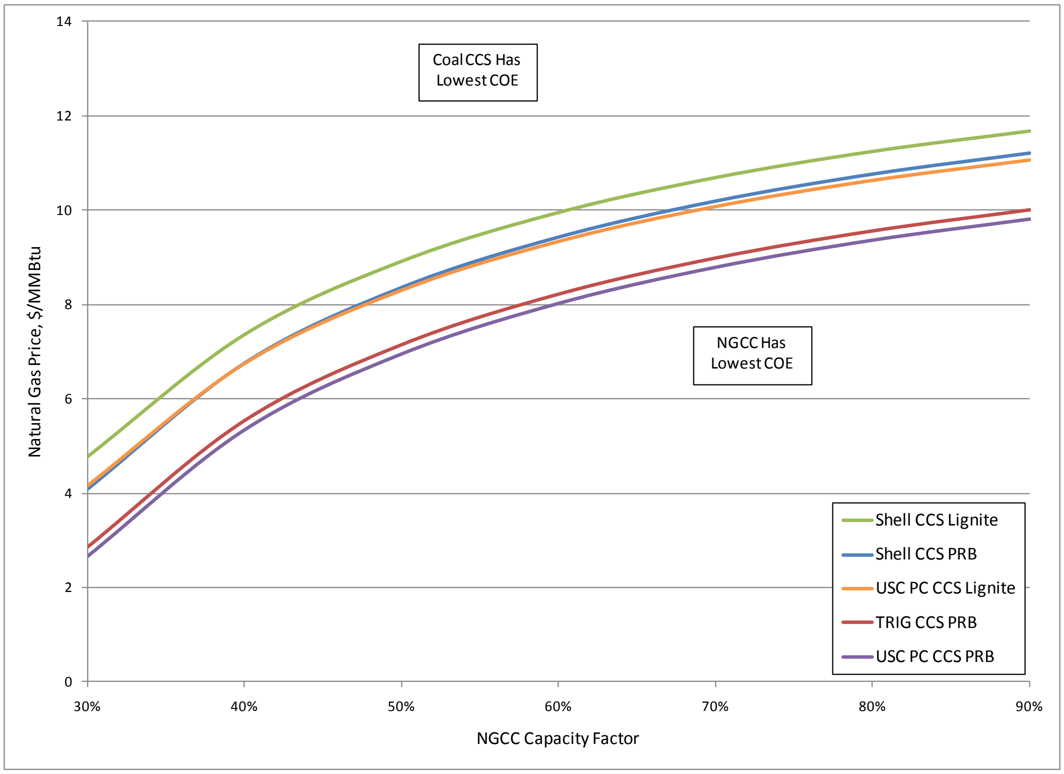
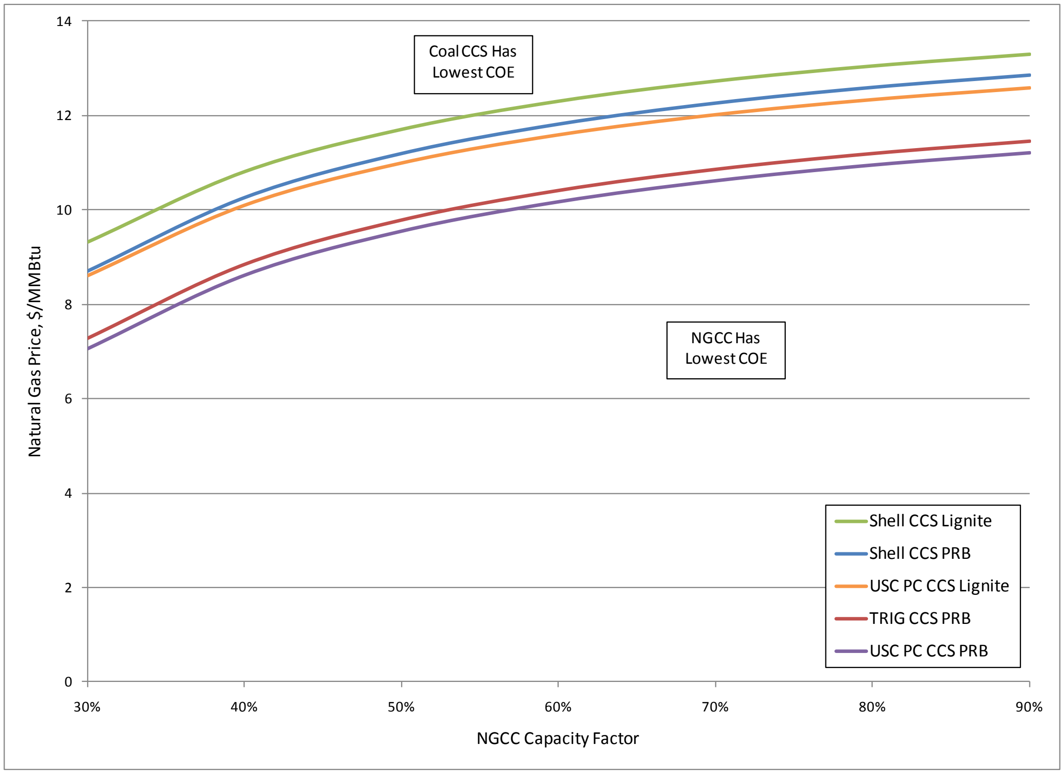


Exhibit ES-22 CCS Sensitivity to Non-Capture NGCC CF and NG Price with \$67/tonne CO_2 Emission Price



ENVIRONMENTAL PERFORMANCE

The environmental targets are based on presumed best available control technology (BACT) for each technology and are summarized in Exhibit ES-23. This study was conducted prior to the issuance of the EPA proposed rules "National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units," and consequently the emissions limits included in this proposed rule are not considered in this study. Emissions rates of mercury (Hg) are shown in Exhibit ES-24, for both sites, and emission rates of sulfur dioxide (SO_2), nitrogen oxide (NOx), and particulate matter (PM) are shown graphically in Exhibit ES-25 and Exhibit ES-26.

Exhibit ES-23 Study Environmental Targets

	Technology			
Pollutant	**IGCC**	**PC**	**CFB**	**NGCC**
SO_2	0.0128 lb/MMBtu	0.132 lb/MMBtu		Negligible
NOx	15 ppmv (dry) @ 15% O_2	0.07 lb/MMBtu		2.5 ppmv (dry) @ 15% O_2
PM (Filterable)	0.0071 lb/MMBtu	0.013 lb/MMBtu		Negligible
Hg (PRB)	>90% capture	0.60 lb/TBtu	3.0 lb/TBtu	N/A
Hg (Lignite)	>90% capture	1.12 lb/TBtu	4.8 lb/TBtu	N/A

The primary conclusions that can be drawn are:

- Low NOx burners (LNB) with overfire air and selective catalytic reduction in the PC cases and low bed temperature and selective non-catalytic reduction in the CFB cases achieve the 0.07 lb/MMBtu NOx emission limit. A NOx emissions limit of 15 ppmv was achieved in the IGCC cases using LNBs and syngas dilution to the combustion turbine. NGCC emissions were limited using dry LNB and an SCR to achieve 2.5 ppmv. For these concentration based emissions limits, the resulting emissions on a lb/MMBtu basis for the coal-based systems vary slightly because of the variable coal feed rates and flue gas volumes generated among cases.
- A dry FGD with baghouse in PC cases and cyclones and a baghouse in the CFB cases were able to achieve the 0.013 lb/MMBtu PM emission limit. A combination of cyclones, candle filters, and scrubbers were assumed to achieve the IGCC particulate limit of 0.0071 lb/MMBtu.
- Sulfur emissions are uniformly low and vary with coal type and technology type. The AGR in the IGCC cases removes upwards of 99 percent of the sulfur as H_2S, which is then recovered in the Claus plant as elemental sulfur. In-bed limestone injection in the CFB cases is assumed to have an SO_2 removal efficiency of 94 percent while the spray dryer absorbers used in the PC cases is assumed to have a removal efficiency of 93

percent. While PRB and lignite coals have the similar sulfur content on an as-received basis, more lignite coal is required to generate the same amount of electricity because of its lower heating value. As a consequence, more SO_2 is emitted at a constant capture efficiency in the lignite coal cases.

- In combustion-based CO_2 capture cases the sulfur concentration is reduced even further to maintain the performance of the amine-based solvents through the use of a dry polishing scrubber ahead of the absorber.
- Lignite coal inherently has higher concentrations of mercury (and lower heating value) than the PRB coal, so the lignite cases result in higher mercury emissions. Using activated carbon beds, the IGCC cases are able to achieve the environmental targets. For combustion cases, mercury emissions are higher for lignite coal cases compared to the analogous PRB coal cases because there is no co-benefit capture with lignite coals while PRB coal cases achieve some co-benefit capture. Mercury emissions are lower for the CFB cases because of higher co-benefit capture in addition to the use of carbon injection.

Exhibit ES-24 Mercury Emissions Rates

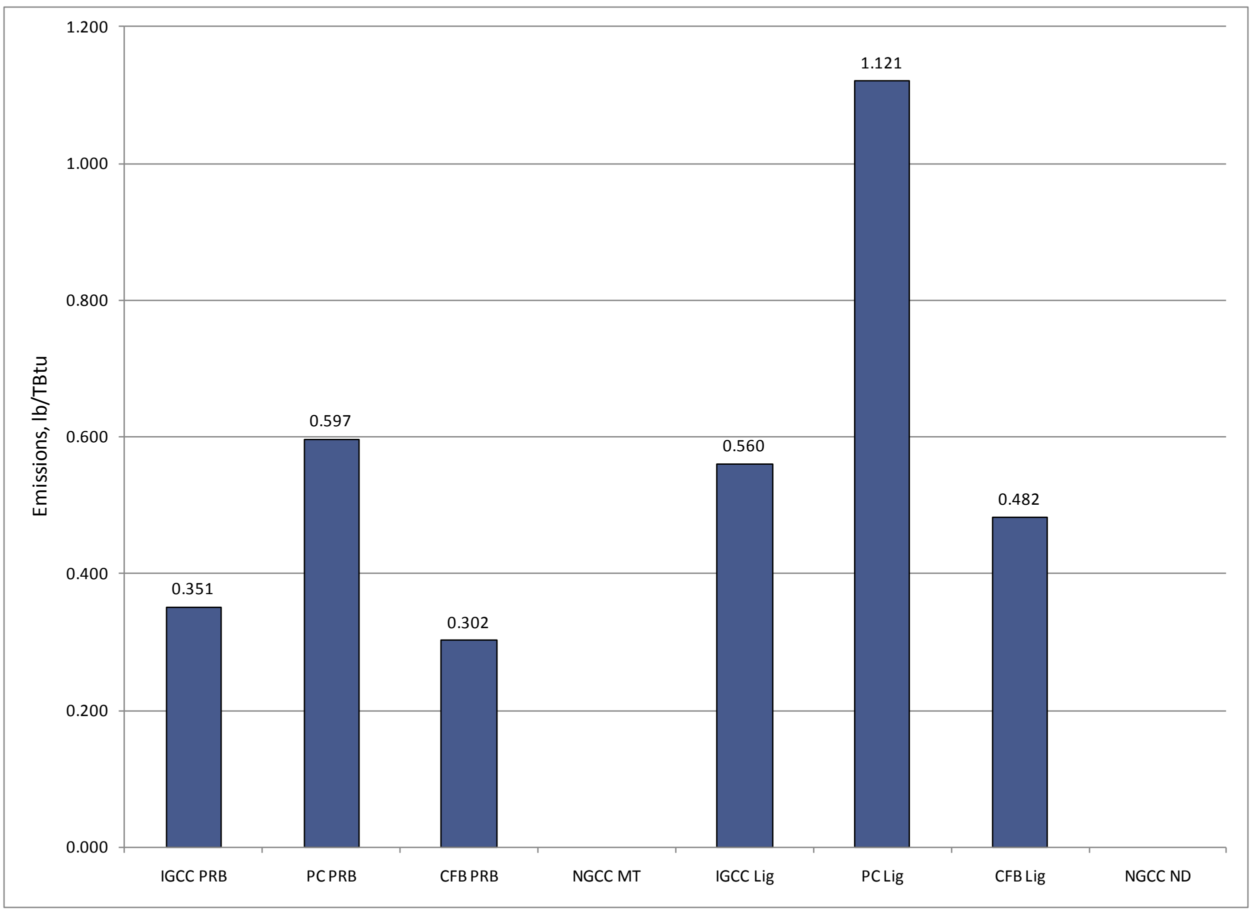


Exhibit ES-25 SO_2, NOx, and Particulate Emission Rates for Montana Site

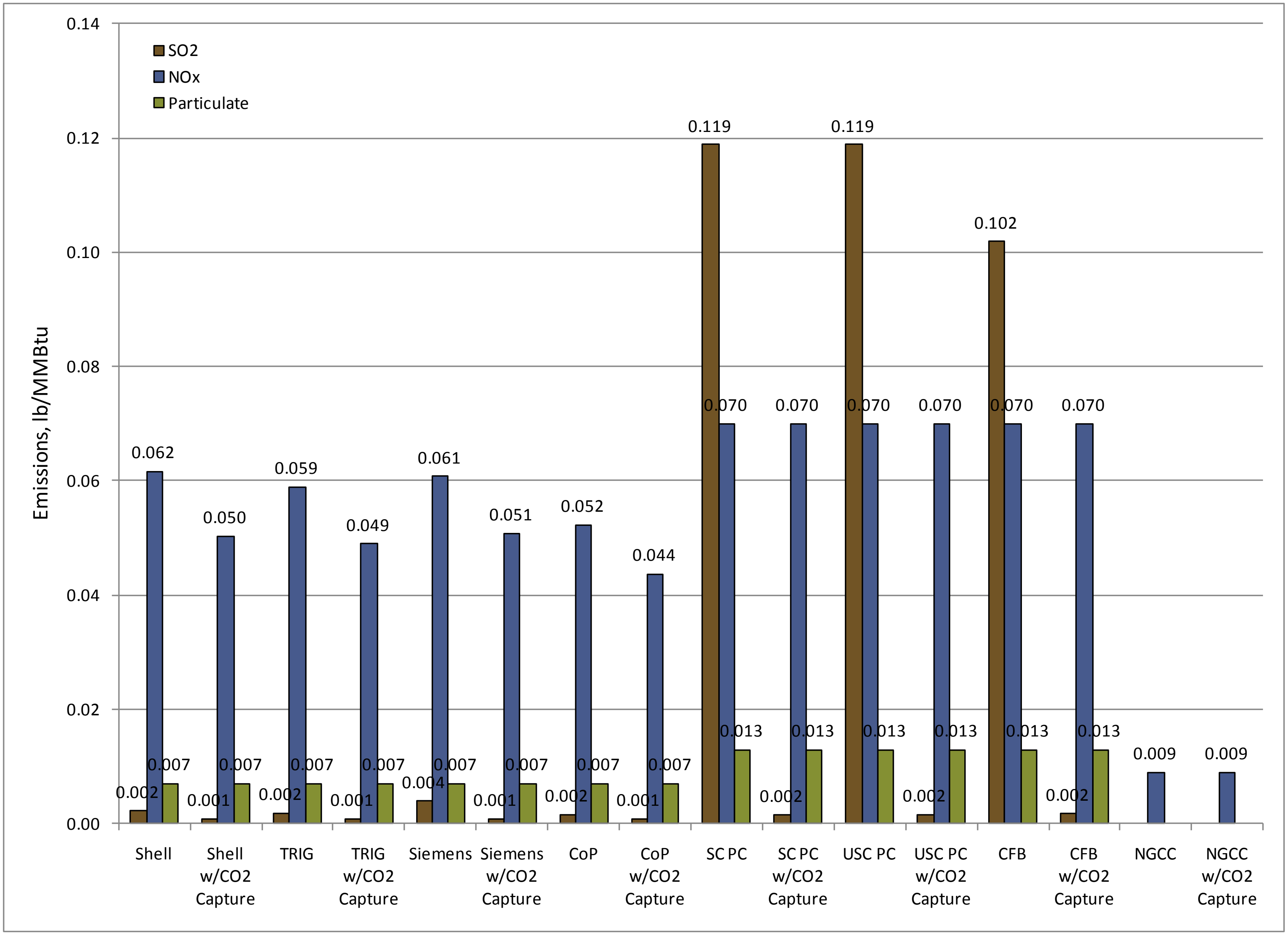
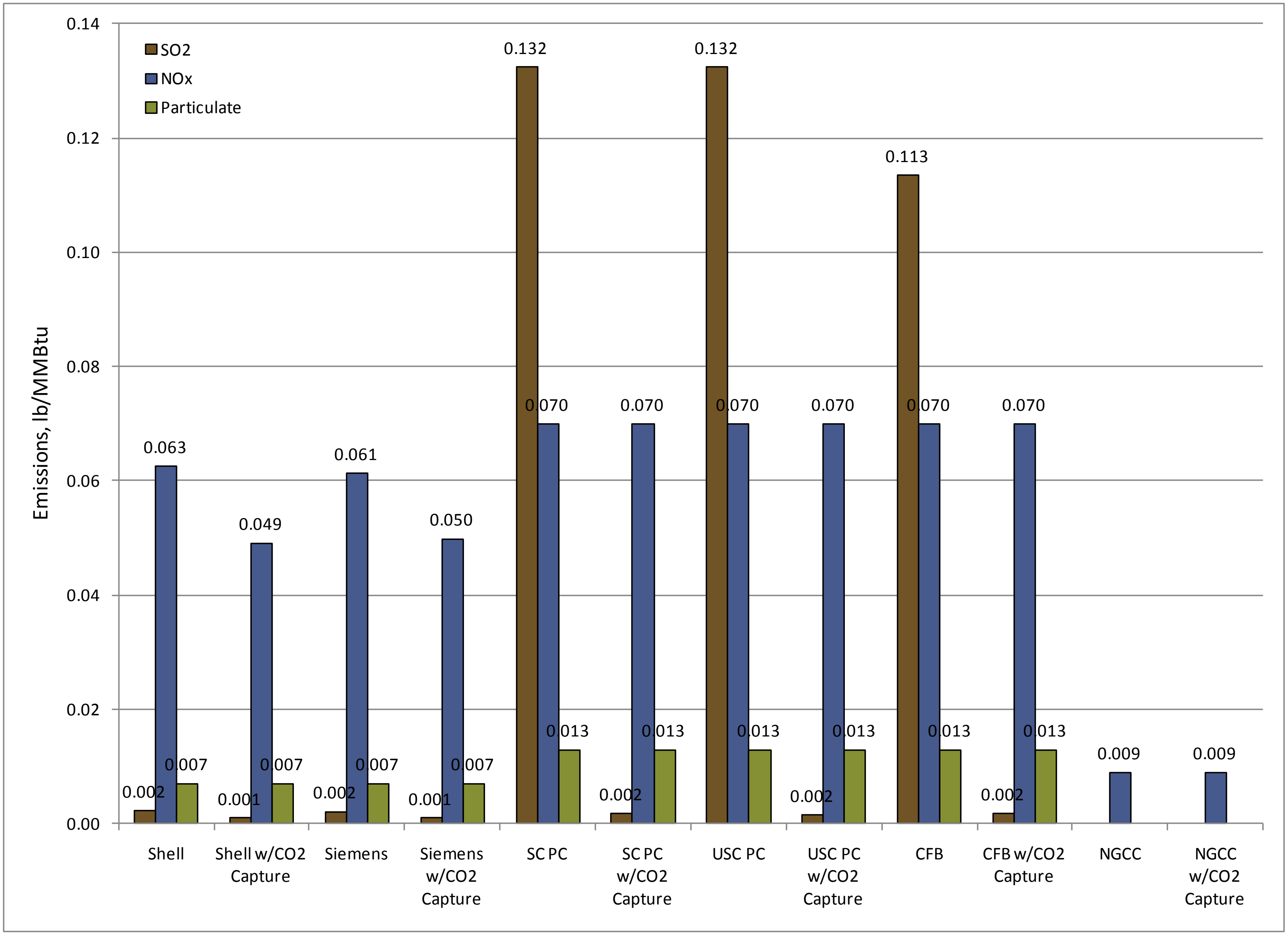


Exhibit ES-26 SO_2, NOx, and Particulate Emission Rates for North Dakota Site



CO_2 Emissions

CO_2 emissions are not currently regulated. However, since there is increasing momentum for establishing carbon limits, it was an objective of this study to examine the relative amounts of CO_2 capture achievable among the six technologies. CO_2 emissions are presented in Exhibit ES-27 and Exhibit ES-28 for the two sites, normalized by net output. In each results summary table emissions are reported on both a net and gross MWh basis. New Source Performance Standards (NSPS) contain emission limits for SO_2 and NOx on a lb/(gross) MWh basis. However, since CO_2 emissions are not currently regulated, the potential future emission limit basis is not known and CO_2 emissions are presented in both ways. The following conclusions can be drawn:

- In cases with no CO_2 capture, NGCC emits 56 percent less CO_2 than the lowest PC case and 54 percent less CO_2 than the lowest IGCC case per unit of net output comparing each respective site. The NGCC CO_2 emissions reflect the lower carbon intensity of natural gas relative to coal and the higher cycle efficiency of NGCC relative to IGCC and PC. Based on the fuel compositions used in this study, natural gas contains 41 lb carbon/MMBtu and the PRB and ND lignite coals contain 59 lb/MMBtu of heat input.
- The CO_2 reduction goal in this study was a nominal 90 percent, which is achieved for all cases except the TRIG IGCC, which remove 83% of the CO_2, in part due to the high cold gas efficiency and high methane concentration. The result is that the controlled CO_2 emissions follow the same trend as the uncontrolled cases, i.e., the NGCC case emits less CO_2 than the IGCC cases, which emit less than the PC cases.
- Among the non-capture coal cases the highest efficiency cases have the lowest emissions, after accounting for the carbon intensity of the fuels. The range of emissions rates for the CO_2 capture cases is tightened after 90% of the carbon is captured and sequestered.

Exhibit ES-27 CO_2 Emissions Normalized By Net Output for Montana Site

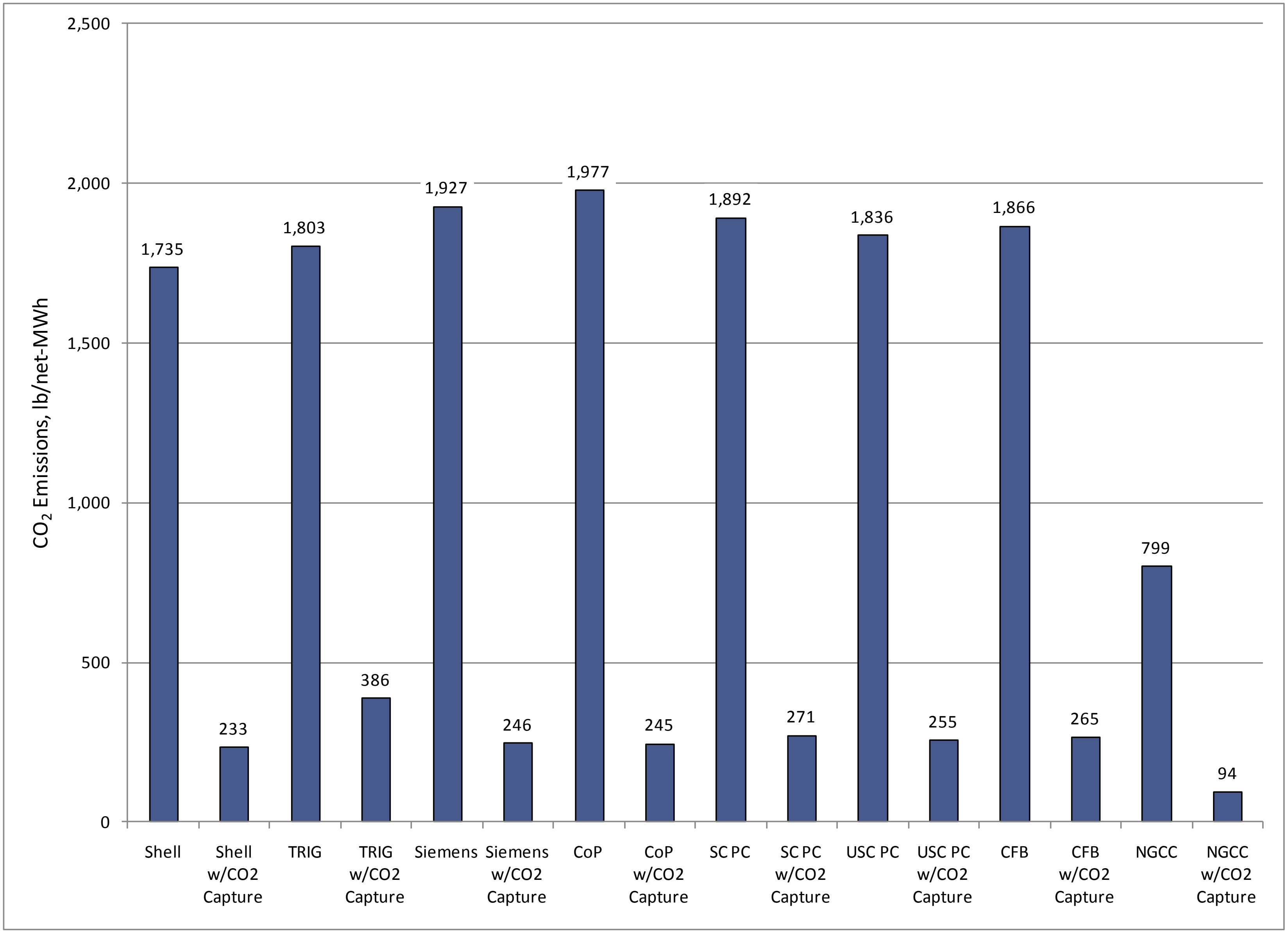
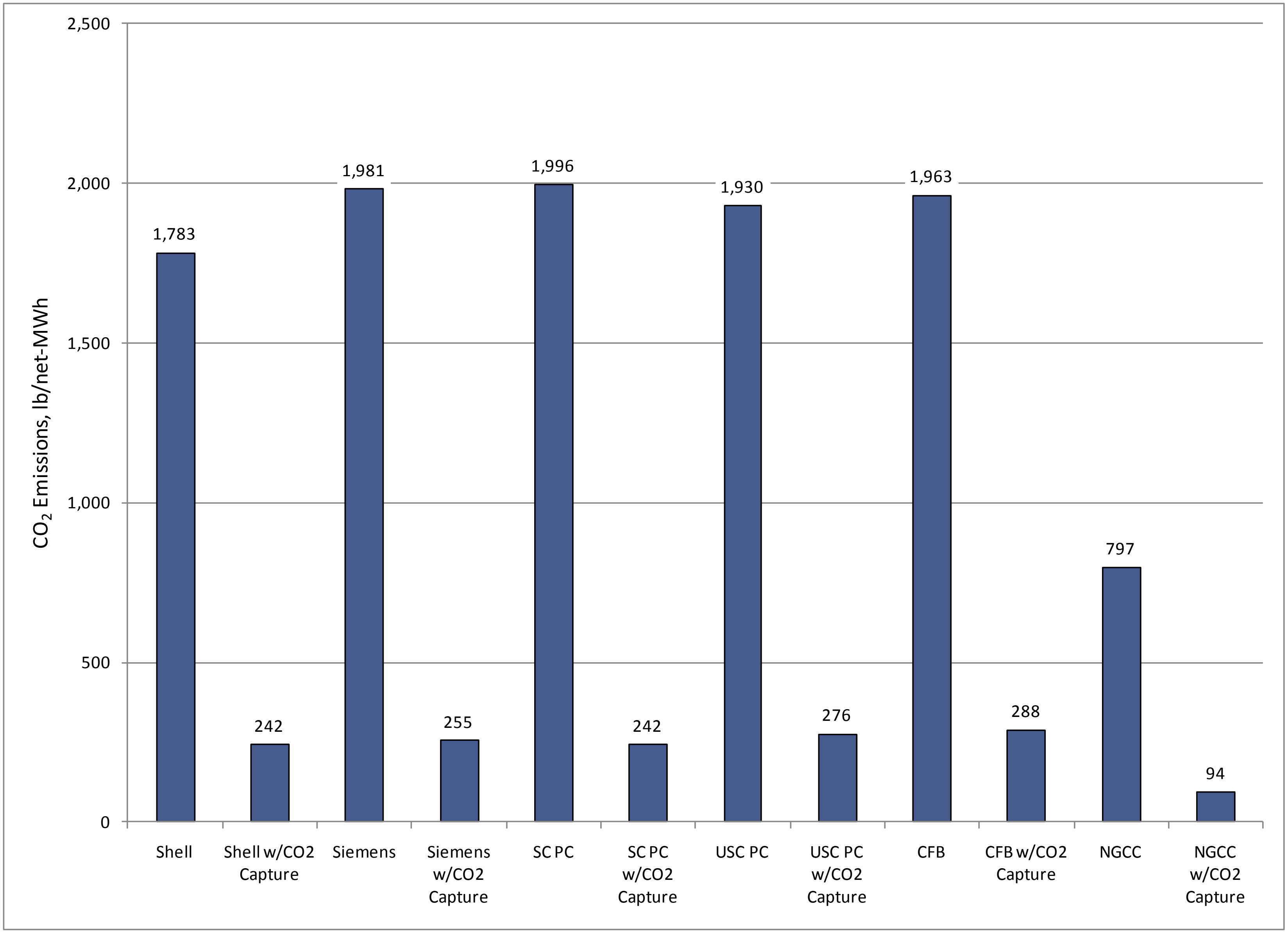


Exhibit ES-28 CO_2 Emissions Normalized By Net Output for North Dakota Site



CO_2 Emission Price Impact

In the event that future legislation assigns a cost to carbon emissions, all of the technologies examined in this study will become more expensive. The technologies without carbon capture will be impacted to a larger extent than those with carbon capture, and coal-based technologies will be impacted more than natural gas-based technologies. The most economical option for each technology is used for the COE sensitivity to carbon emissions price shown for the Montana site cases in Exhibit ES-29 and for the North Dakota site cases in Exhibit ES-30. Thus, the PC technology is represented by the SC PC cases and the IGCC technology is represented by the TRIG cases for the Montana site and the Shell cases for the North Dakota site.

The curves represent the base study design conditions, capacity factor, and fuel prices used for each technology; namely 80 percent capacity factor for IGCC plants and 85 percent for PC and NGCC plants, and $0.89/MMBtu for the PRB coal and $0.83/MMBtu for the lignite coal and $7.13/MMBtu for natural gas. Natural gas fuel prices are more volatile than coal and tend to fluctuate over a fairly large range. The dispatch-based capacity factor for NGCC plants is significantly less than 85 percent and would result in a higher COE as was shown in the capacity factor sensitivity.

Exhibit ES-29 Sensitivity to Carbon Emissions Price for Montana Site

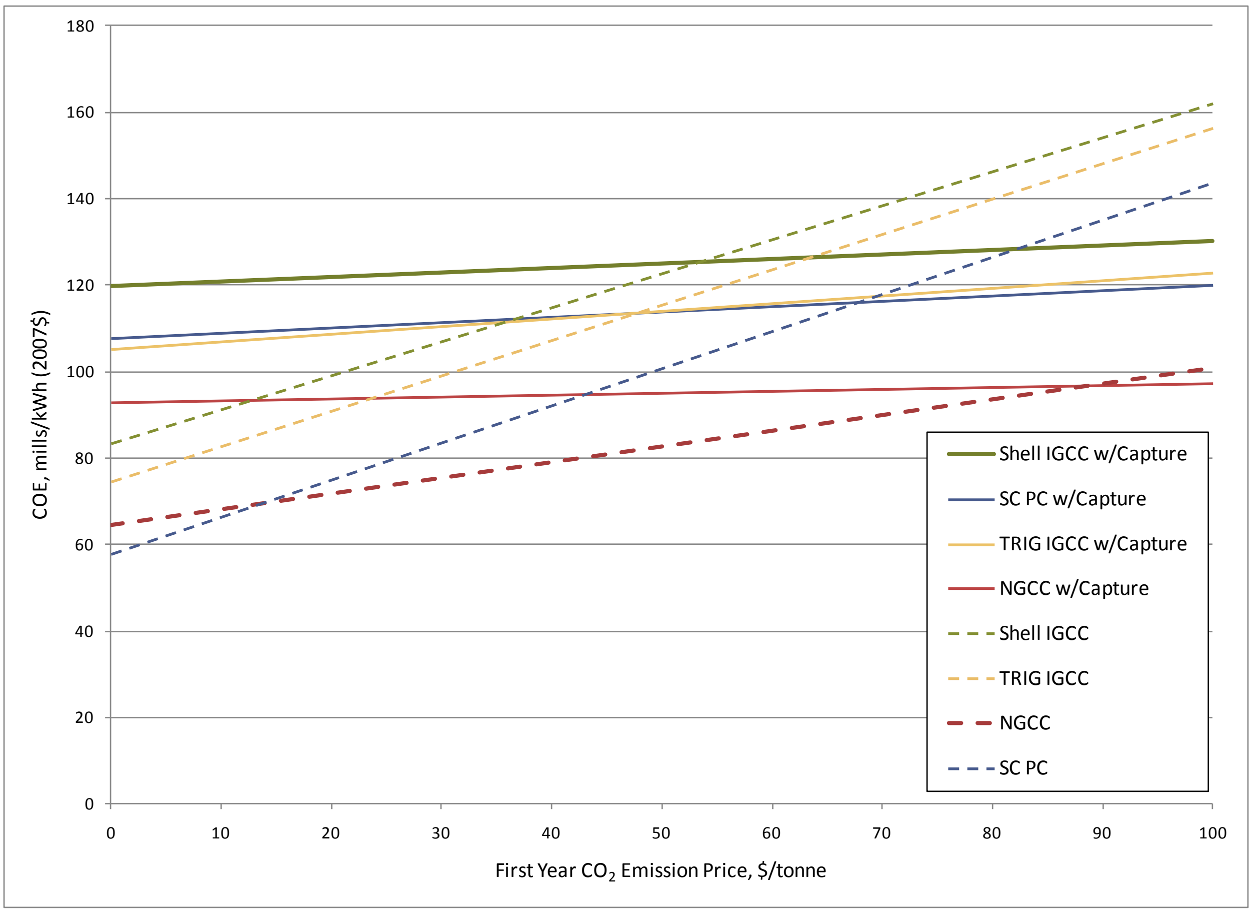
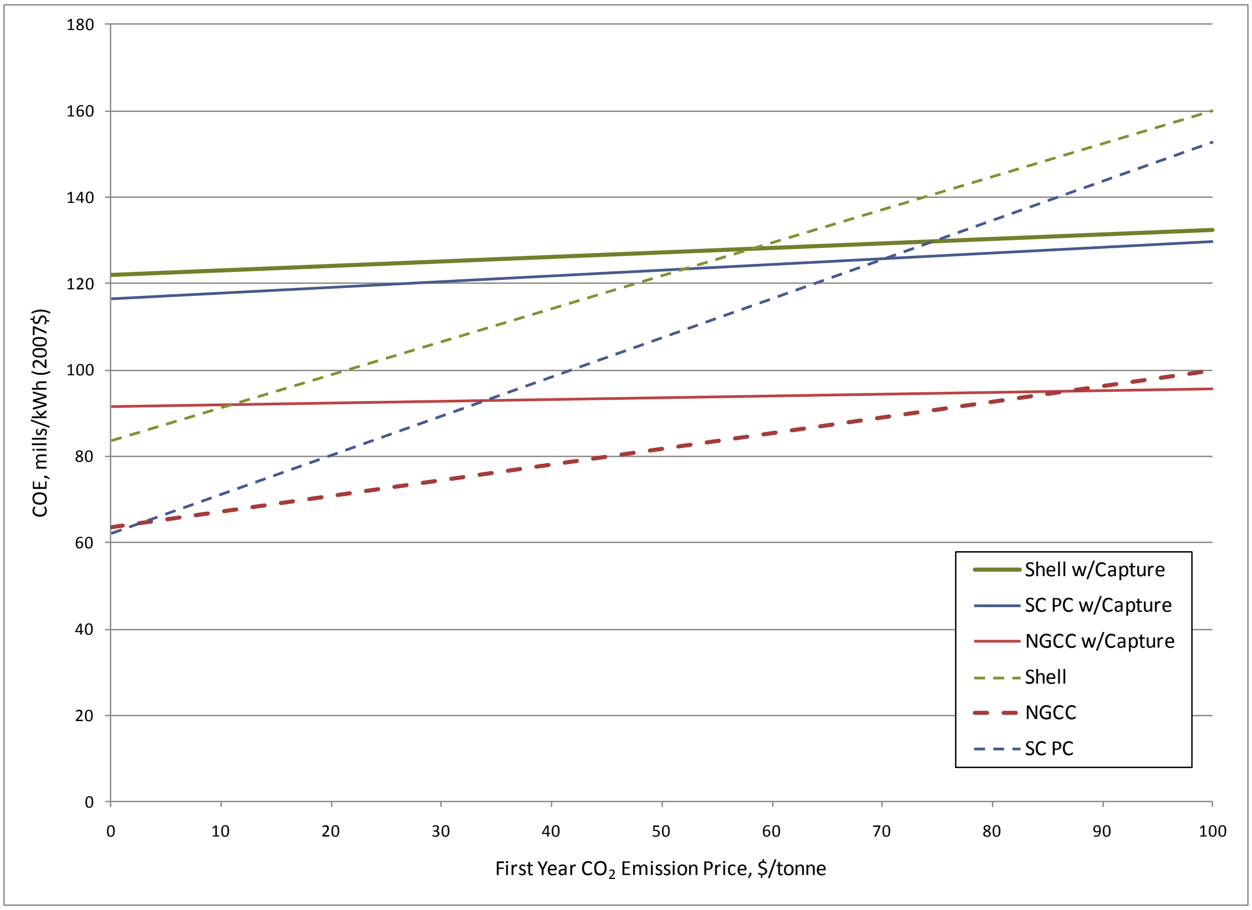


Exhibit ES-30 Sensitivity to Carbon Emissions Price for North Dakota Site



The intersection of the capture and non-capture curves for a given technology gives the cost of CO_2 avoided for that technology. For example, the cost of CO_2 avoided is $68/tonne for SC PC and $89/tonne for NGCC at the Montana site, and $70/tonne and $87/tonne for the North Dakota site. These values can be compared to those shown in Exhibit ES-14.

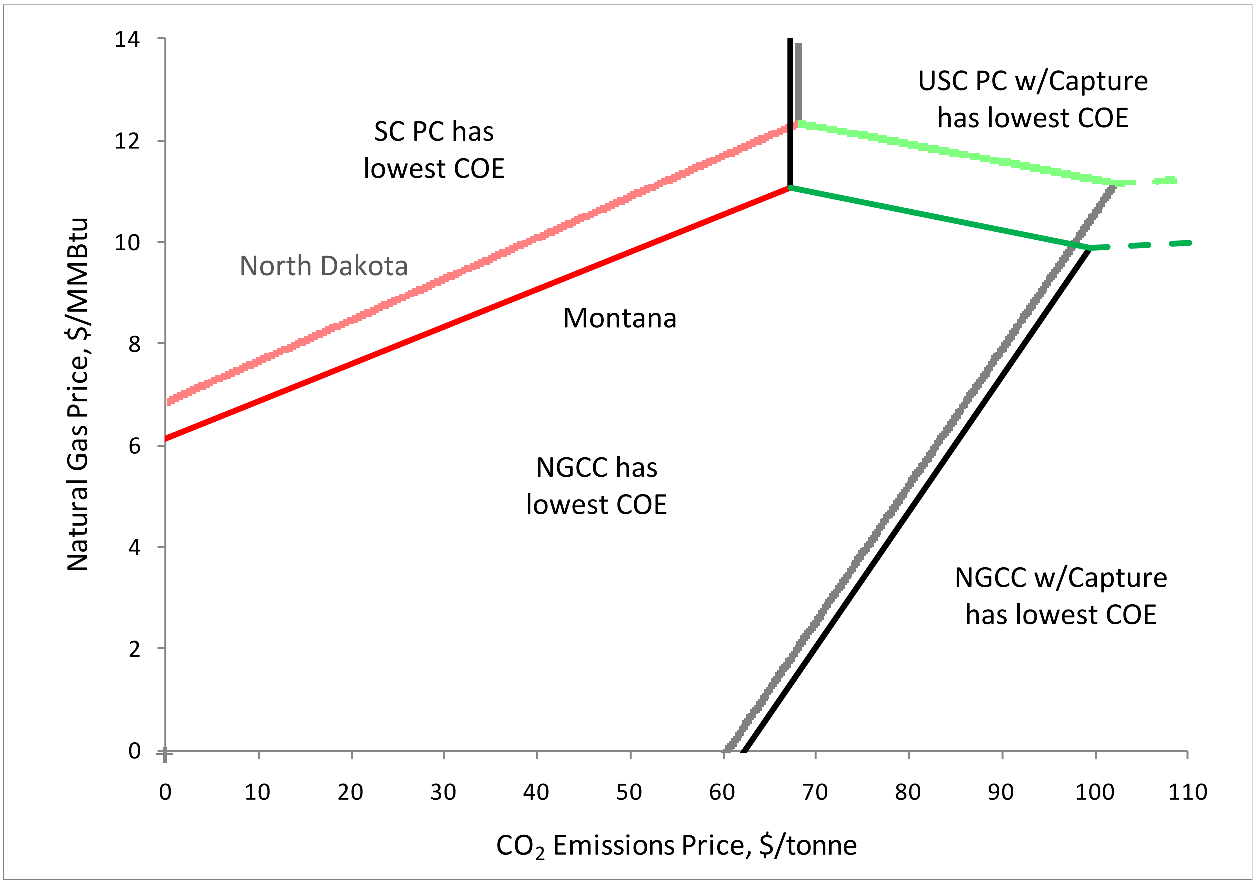
The following conclusions can be drawn from the carbon emissions price graph:

- At the baseline study conditions any cost applied to carbon emissions favors NGCC technology. While PC and NGCC with no capture start at essentially equivalent COEs, they diverge rapidly as the CO_2 emission cost increases. The lower carbon intensity of natural gas relative to coal and the greater efficiency of the NGCC technology account for this effect.
- The SC PC and IGCC curves are nearly parallel indicating that the CO_2 emission price impacts the two technologies nearly equally. As the CO_2 emission price increases from zero, the two technologies gradually converge due to the slightly lower efficiency of SC PC relative to the IGCC.
- For the coal-based technologies, adding CO_2 capture becomes the favored configuration compared to SC PC with no capture at an emission price above approximately $70/tonne.

Combined CO_2 Emission and Natural Gas Price Parity

The relationship between technologies and CO_2 emission pricing can also be considered in a "phase diagram" type plot as shown in Exhibit ES-31. The lines in the plot represent cost parity between different pairs of technologies, combining the CO_2 emissions price and natural gas price sensitivities to determine the lowest cost generating option at all combinations of these economic parameters. The darker lines represent the Montana site cases and the lighter lines represent the North Dakota site cases.

Exhibit ES-31 Lowest Cost Technology Parity Sensitivity to CO_2 and NG Prices



The lowest cost technology selection for the given CO_2 emission and natural gas price follows the same trend for both the Montana and North Dakota site: NGCC dominates at low natural gas prices. The PC cases are the next attractive technology once natural gas prices exceed the colored horizontal lines. The black vertical lines demarcate the economic conditions where including CO_2 capture to the base plant configuration results in the lowest overall COE. The slopes of the lines are a function of the relative CO_2 intensities of the technologies as well as the natural gas cases sensitivity to fuel price.

When the parity charts are overlaid, it becomes apparent that the NGCC cases occupy a larger area as the lowest cost generating option at the North Dakota site, due in part to the reduced combustion turbine derate at lower elevation. The vertical black break even lines for the Montana site occur at slightly higher CO_2 emissions prices compared to the North Dakota site.

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3 “Cost and Performance Baseline for Fossil Energy Plants, Volume 3c: Natural Gas Combined Cycle at Elevation”, DOE/NETL-2010/1396, March 2011

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