CO_2 Capture From *Existing* Coal-Fired Power Plants

Capture Technology Choices and Costs

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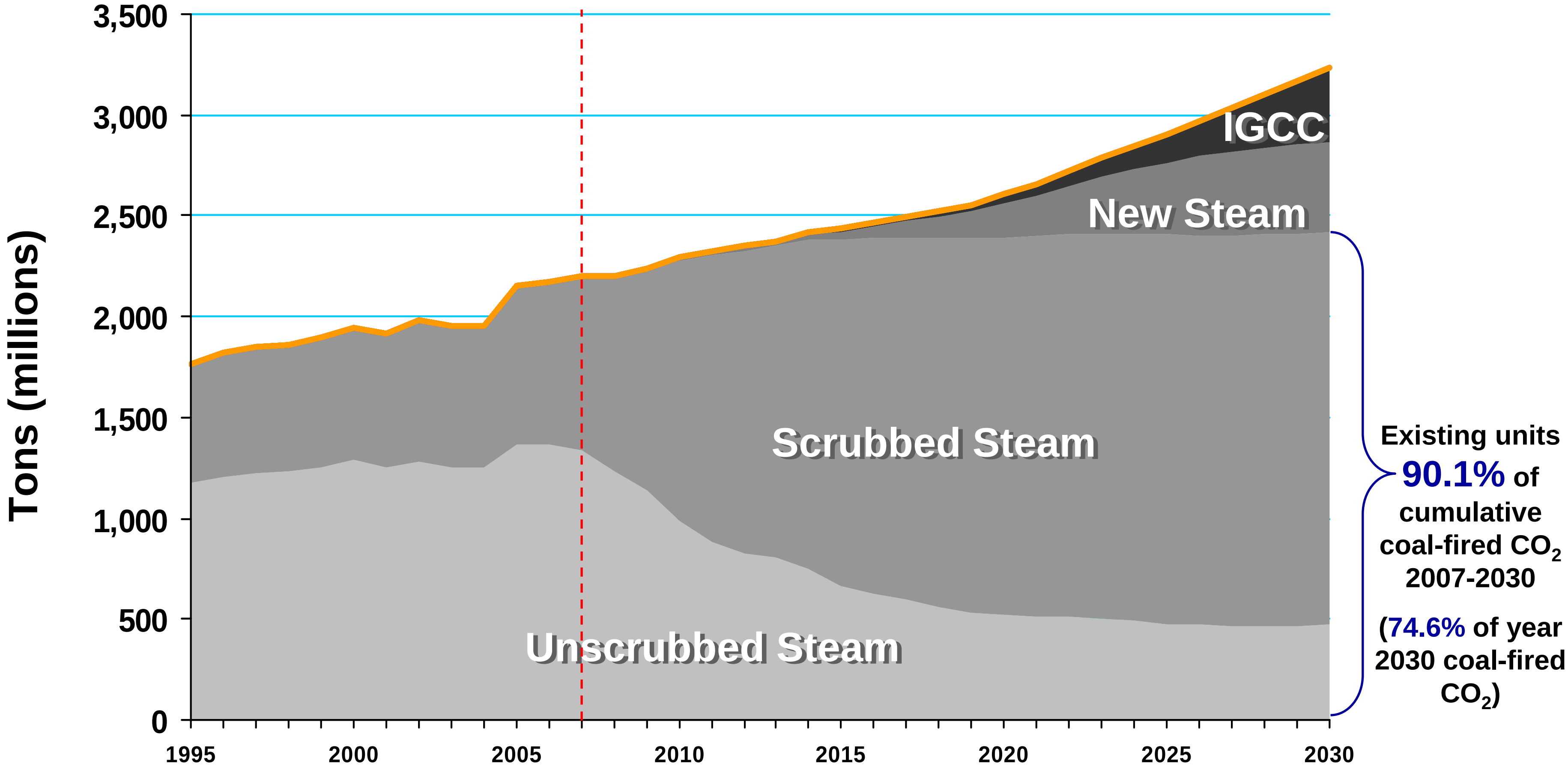
Office of Systems Analysis and Planning (OSAP)
Functional Teams

- **Systems**
  - oriented toward technologies and processes
  - focused on systems inside the plant boundary
- **Situational Analysis**
  - oriented toward issues and policies
  - focused on higher-level, macro-systems
- **Benefits**
  - oriented toward program metrics
  - focused on evaluation of R&D programs, assessment of national benefits, “What if?” Studies
- **Extensive Collaboration Among Teams**

Coal-fired Generation CO_2 Forecast

AEO'07 Reference Case



Large Proportion of Total Coal-fired CO_2 From Existing Plants

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Key Questions

If carbon constraints are mandated in the U.S. then…..

1. What are the key challenges associated with PC retrofits?

2. What are the CO_2 capture technology options available **today** for existing plants?

3. What are the economics of retrofitting an **existing** pulverized coal plant with various levels of CO_2 capture?

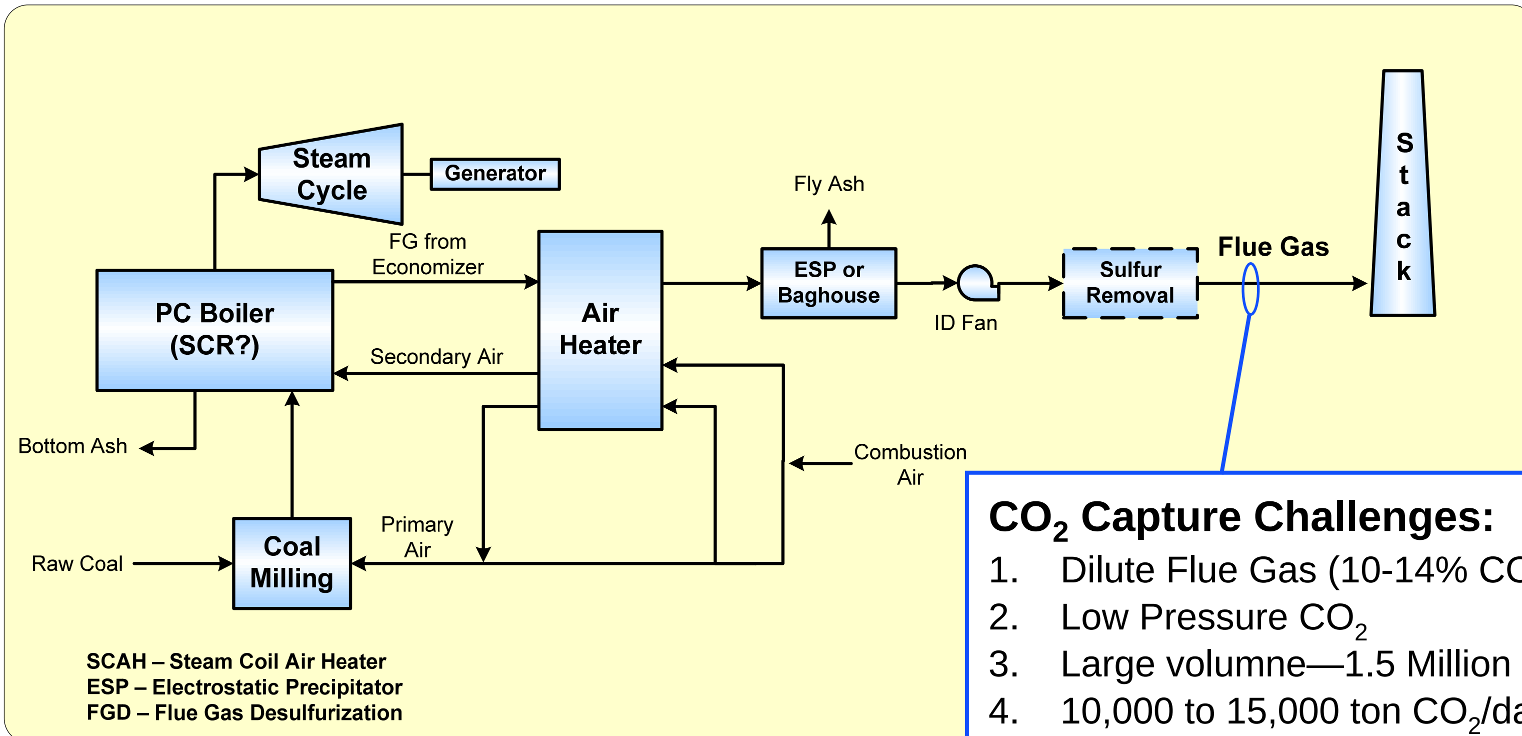
4. Is there a way to significantly reduce CO_2 capture cost for the **existing** fleet?

5. What level of CO_2 recovery is economically optimal or necessary to meet proposed regulations?

Key Challenges to PC CO_2 Retrofits

1. Space limitations — acres needed for current scrubbing
2. Major equipment modifications or redundancy
3. Regeneration steam availability — can steam turbine operate at part load?
4. Sulfur — additional deep sulfur removal required for most CO_2 sorbents
5. Make-up power — satisfy need to maintain baseload output
6. *Local storage availability (saline formation, EOR)
7. *Scheduling outages for CO_2 retrofits
8. *Post-retrofit dispatch implications due to increase in COE
9. *Retrofit triggering NSPS review
10. *Proposed legislation

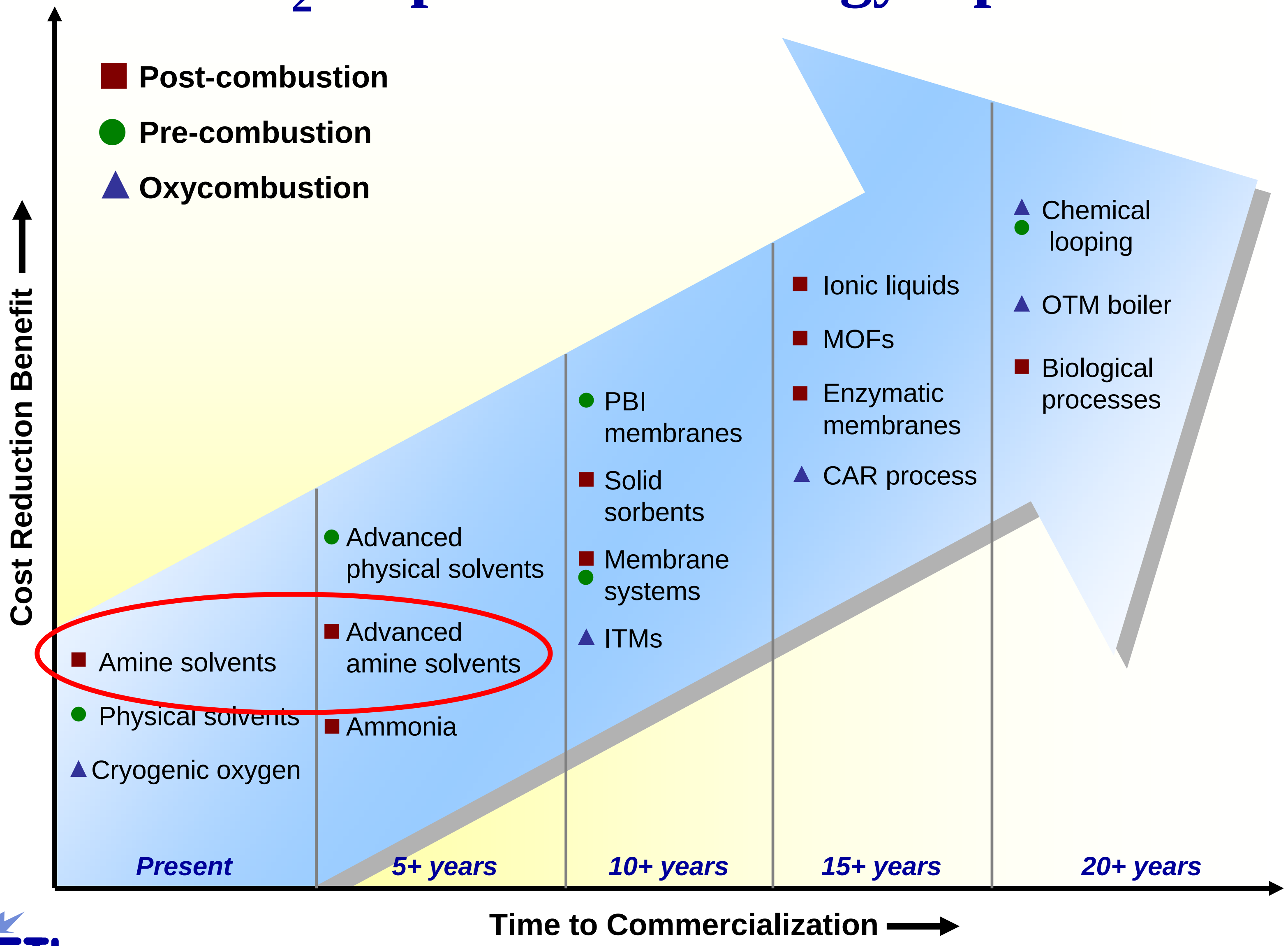
Existing Pulverized Coal Power Plant



CO_2 Capture Challenges:

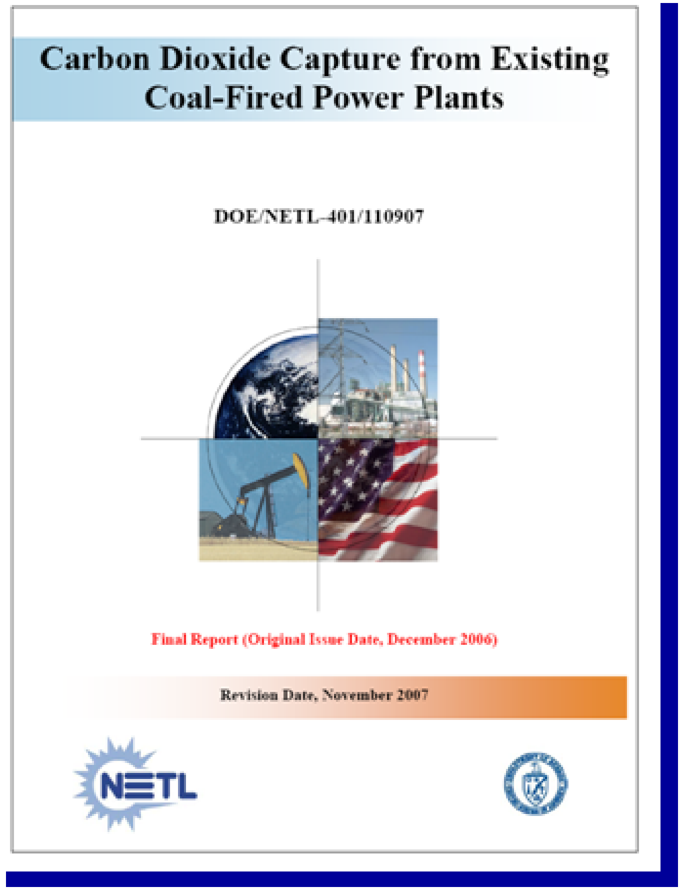
1. Dilute Flue Gas (10-14% CO_2)
2. Low Pressure CO_2
3. Large volumne—1.5 Million scfm
4. 10,000 to 15,000 ton CO_2/day
5. Large Parasitic Loads (Steam + CO_2 Compression)
6. SOx/NOx contaminants

CO_2 Capture Technology Options



Carbon Sequestration From Existing Power Plants Feasibility Study (2007)

Randall Gas Technologies


Carbon Dioxide Capture from Existing Coal-Fired Power Plants

DOE/NETL-401/110907

Final Report (Original Issue Date, December 2006)

Revision Date, November 2007

Location: AEP Conesville Unit #5

- **Total 6 units = 2,080 MWe**
- **Unit #5:**
  - Subcritical steam cycle (2400psia/1005^{o}F/1005^{o}F)*
  - Constructed in 1976
  - 463 MW gross (~430 MW net)
  - ESP and Wet lime FGD (95% removal efficiency, 104 ppmv)

Mid-western bituminous coal

Ultimate Analysis (wt.%)	As Rec'd
Moisture	10.1
Carbon	63.2
Hydrogen	4.3
Nitrogen	1.3
Sulfur	2.7
Ash	11.3
Oxygen	7.1
HHV (Btu/lb)	11,293

Detailed Systems Analysis Scope

1. Assess 30%, 50%, 70%, 90% and CO_2 capture levels
2. Employ CO_2 scrubbing technology advances
3. Detailed steam turbine analysis by ALSTOM's steam turbine retrofit group
4. Employ CO_2 capture and compression heat integration
5. Site visits to specify exact equipment location
6. Include make-up power costs in economic analysis

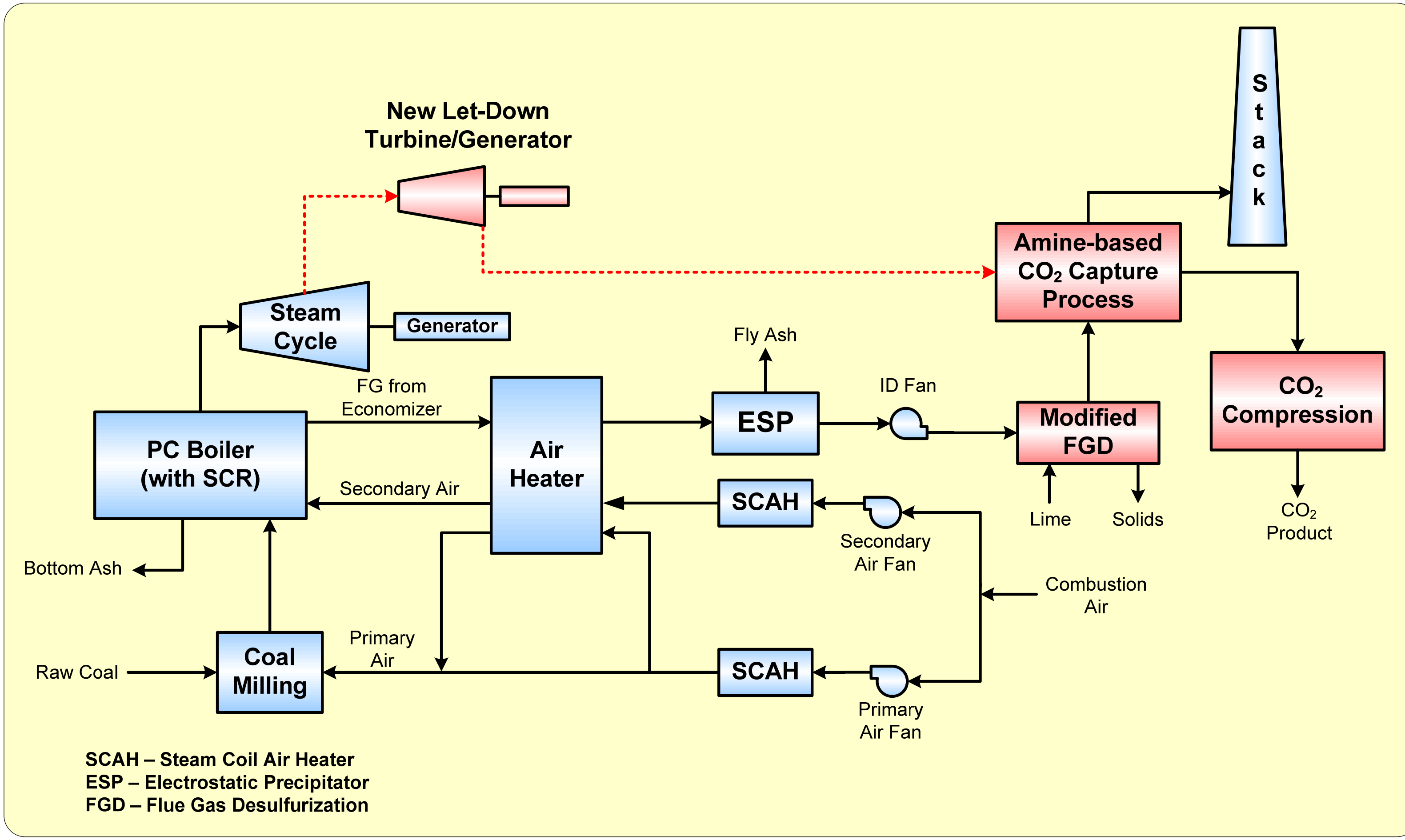
Design Basis: Assumptions

Economic

Dollars (Constant)	2006
Depreciation (Years)	20
Equity (%)	55
Debt (%)	45
Tax Rate (%)	38
After-tax Weighted Cost of Capital (%)	9.67
Capital Charge Factor (%)	17.5
Capacity Factor (%)	85
Make-up Power Cost (¢/kWh)	6.40

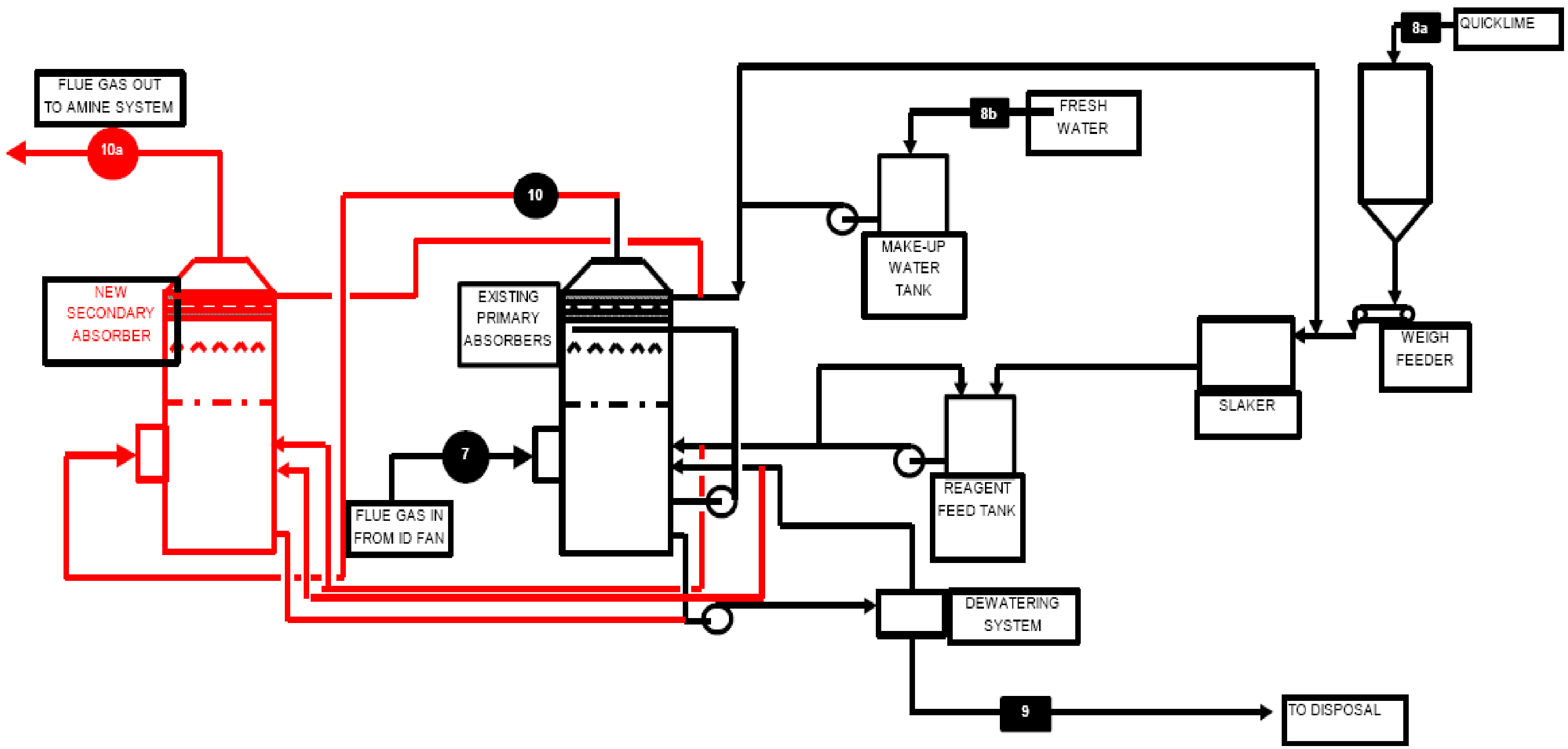
CO_2 Transport and Storage Costs not included

Existing Plant Modifications



Modified FGD Process

1. Second stage absorber added to achieve 99.7% SO_2 removal efficiency (6.5 ppmv)
2. Estimated EPC cost for each case (30-90%) is $20.5MM
3. Includes an SO_2 Credit equal to $608/ton in the Variable O&M cost



Amine Scrubbing Improvements Employed

Since ~2000

Potential Retrofit Options	Outcome/Notes
1. Heat Integration	↓ Steam Consumption
2. Minimize equipment needed	↓ Capital cost (ex. No flue gas cooler)
3. Lower cost of materials	↓ Capital cost (stainless vs. carbon steel)
4. Structured column packing	↓ Capital cost, ↓ Sorbent rate (ex. KS1)
5. Plate-and-frame HX	↓ Capital cost
6. ANSI Pumps vs. API Pumps	↓ Capital cost
7. Vapor-recovery system	↓ Steam Consumption
8. Large diameter absorbers	↓ # of Absorbers, ↓ Capital cost
9. Advanced solvents*	↓ Capital cost, ↓ Sorbent circ. rate (ex. KS1)
10. Lower re-boiler duty	↓ Steam Consumption

***Example:**
Current amines (MEA) require at least 1,600 Btu/lb CO_2 captured
Fluor Econamine FG+ requires 1,300-1,400 Btu/lb CO_2 captured
Mitsubishi's KS-1 solvent requires 1,200 Btu/lb CO_2 captured

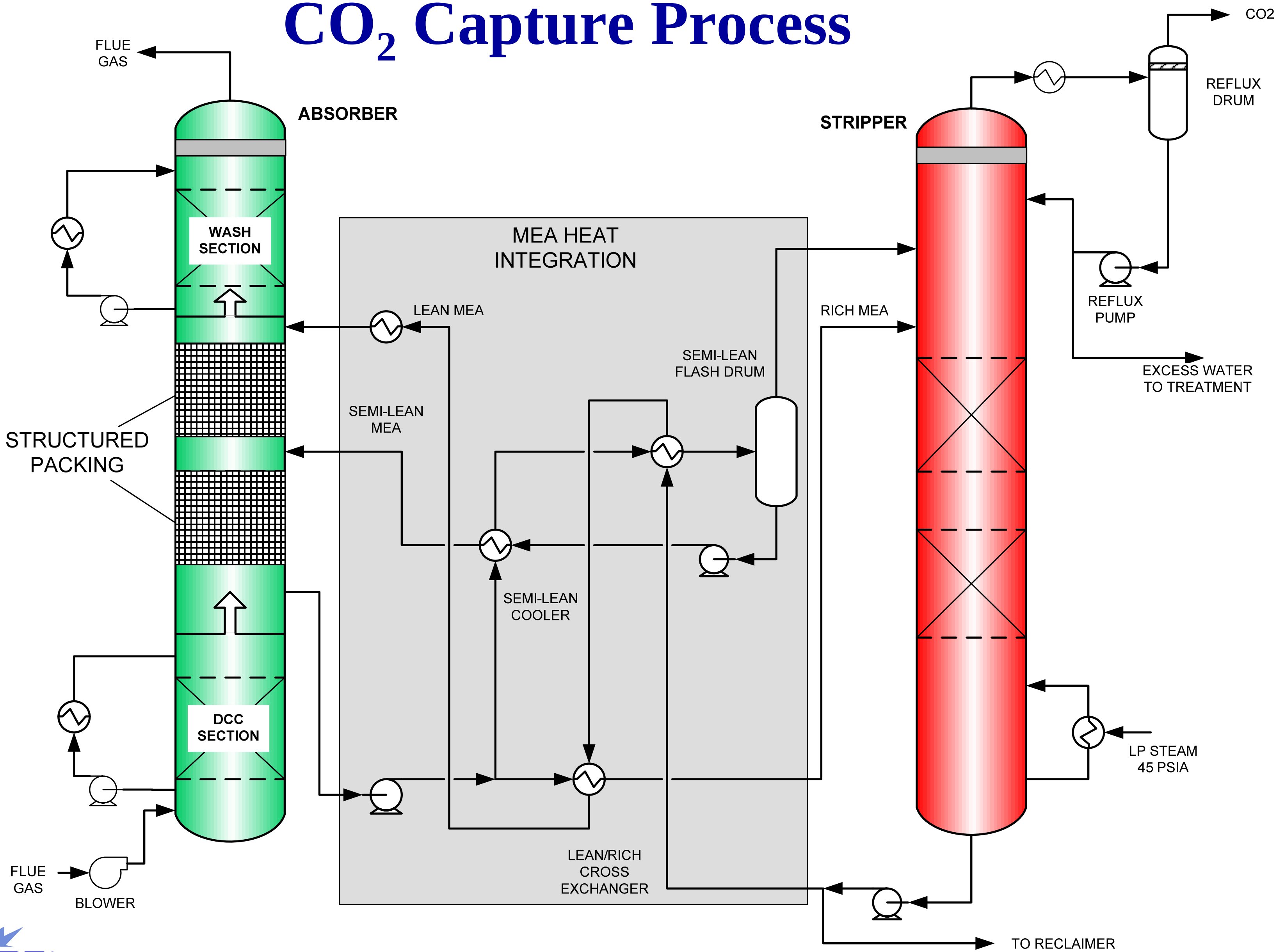
CO_2 Capture Process Parameters

Process Parameter	Units	2007	2001	AES Design
Plant Capacity	Ton/Day	9,350-3,120	9,888	200
CO_2 Recovery	%	90-30	90	96
CO_2 in Feed	mol %	12.8	13.9	14.7
SO_2 in Feed	ppmv	10 (Max)	10 (Max)	10 (Max)
Solvent		MEA	MEA	MEA
Solvent Concentration	Wt. %	**30**	**20**	**17-18**
Lean Loading	mol CO_2/mol amine	**0.19**	**0.21**	**0.10**
Rich Loading	mol CO_2/mol amine	**0.49**	**0.44**	**0.41**
Steam Use	lbs Steam/lb CO_2	**1.67**	**2.6**	**3.45**
Stripper Feed Temp	^oF	205	210	194
Stripper Bottom Temp	^oF	247	250	245
Feed Temp to Absorber	^oF	115	105	108

Note: Additional data in “notes pages”

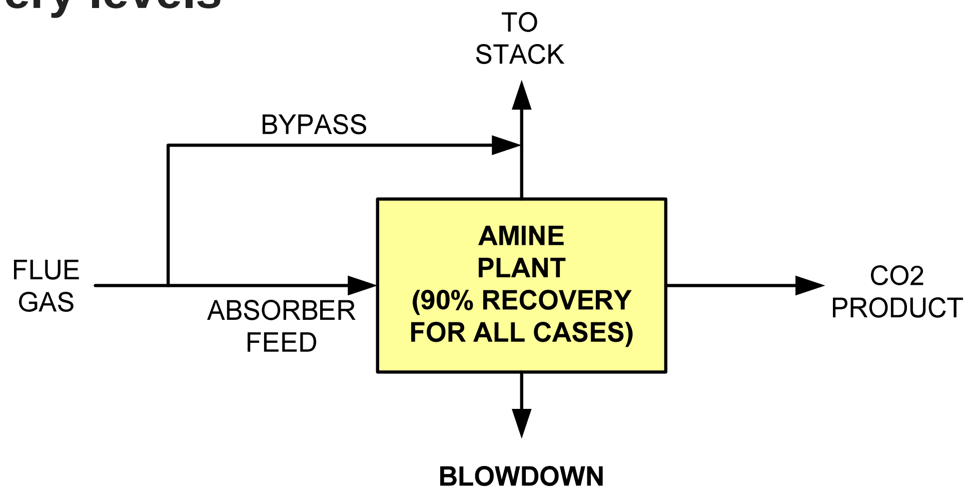
- Reboiler operated at 45 psia—reduced from 65 psia used in 2000 study
- Absorber contains two beds of structured packing

CO_2 Capture Process



Flue Gas Bypass

- Bypass method determined to be least costly method to obtain lower CO_2 recovery levels



CO_2 (Moles/hr)	Case 1 (90%)	Case 2 (70%)	Case 3 (50%)	Case 4 (30%)
FLUE GAS	19,680	19,680	19,680	19,680
BYPASS	0	4,374	8,746	13,120
ABSORBER FEED	19,680	15,306	10,934	6,560
STACK	1,962	5,924	9,846	13,770
CO_2 PRODUCT	17,720	13,766	9,822	5,906
# Trains	2	2	2	1

CO_2 Capture, Compression, Dehydration, and Liquefaction

CO_2 compression to 2,015 psia, EOR specifications

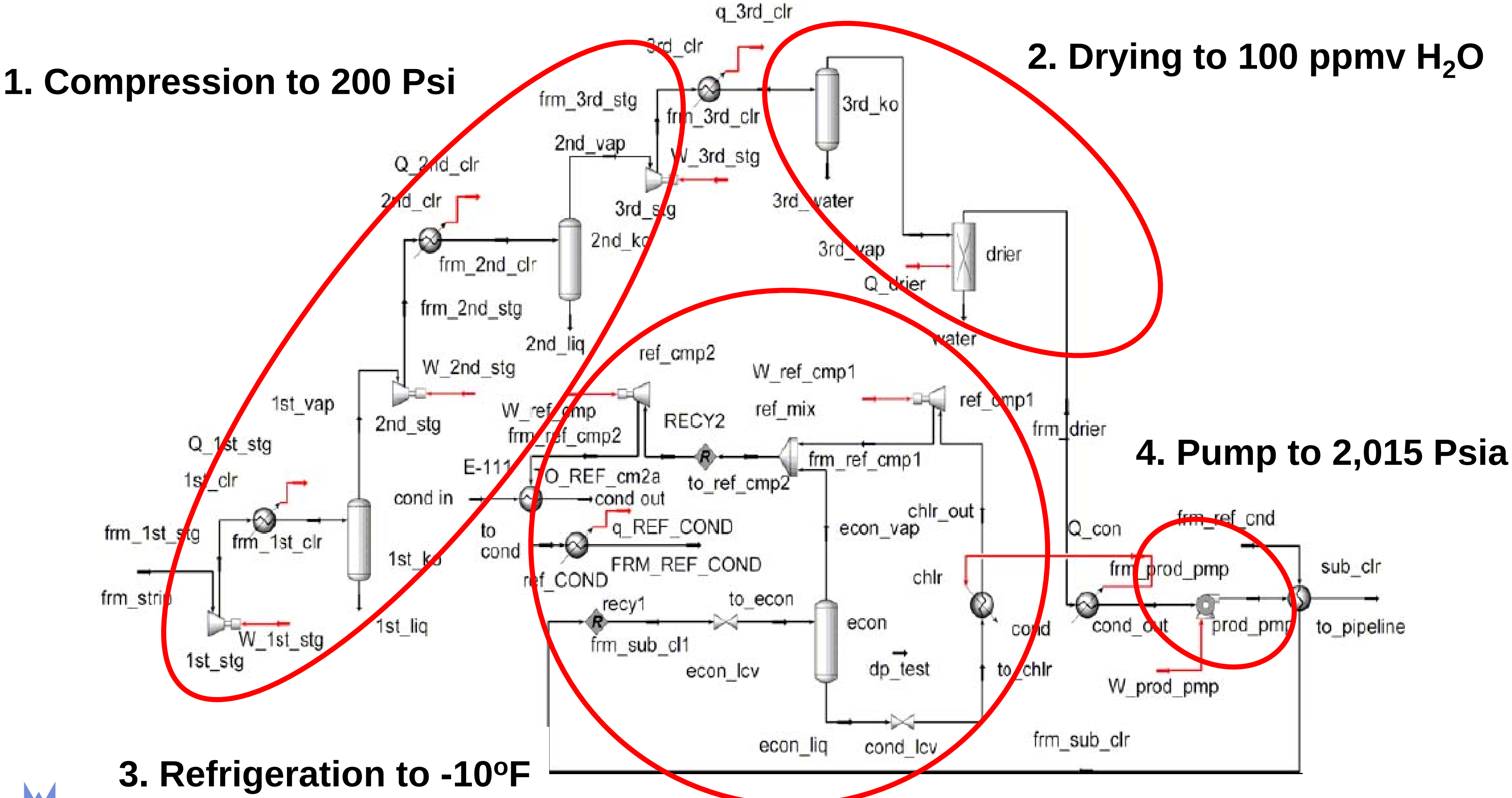
Parameter	Wt %	Vol %	ppmv
Carbon Dioxide	96	94.06	940600
C_2+ and Hydrocarbons	2	2.87	28700
Hydrogen Sulfide	1	1.27	12700
Nitrogen	0.6	0.92	9200
Methane	0.3	0.81	8100
Oxygen	0.03	0.04	400
Mercaptans and Other Sulfides	0.03	0.02	200
Moisture	0.006	0.01	100

Dakota Gasification Pipeline EOR Specification

Four Stage Process:

Compression ⇒ Drying ⇒ Refrigeration ⇒ Pumping

CO_2 Capture Compression, Dehydration and Liquefaction



CO_2 Capture Process Equipment

	2007 Study		2001 Study	
% CO_2 Capture	90		96	
CO_2 Capture Process	No.	ID/Height (ft)	No.	ID/Height (ft)
Absorber	2	34/126	5	27/126
Stripper	2	22/50	9	16/50
Distance from stack	100 ft		1,500 feet	
Heat Exchangers	No.		No.	
Reboilers	10		9	
Stripper CW Cond.	12		9	
Other Heat Exchangers	36		113	
Total Heat Exchangers	**58**		**131**	
CO_2 Compressor	2		7	
Propane Compressor	2		7	
TIC Cost $MM	**370**		**670**	

CO_2 scrubbing technology improvements lead to significant decrease in equipment requirements and capital cost!

Steam Turbine Modifications

Design Assumptions:

1. **Existing turbine/generator required to operate at maximum load in case of a trip of the MEA plant**
   – All pressures to be within a level that no steam will be blown off

2. **Feedwater system modifications to allow CO_2 capture and compression system heat integration**
   – CO_2 compressor intercoolers, stripper overhead cooler, refrigeration compressor cooler

3. **Well within the LP turbine "lower load limit" after significant steam extraction for the 90% case (Conesville #5 instruction manual)**

4. **New Let Down turbine vs. modifying existing LP turbine**

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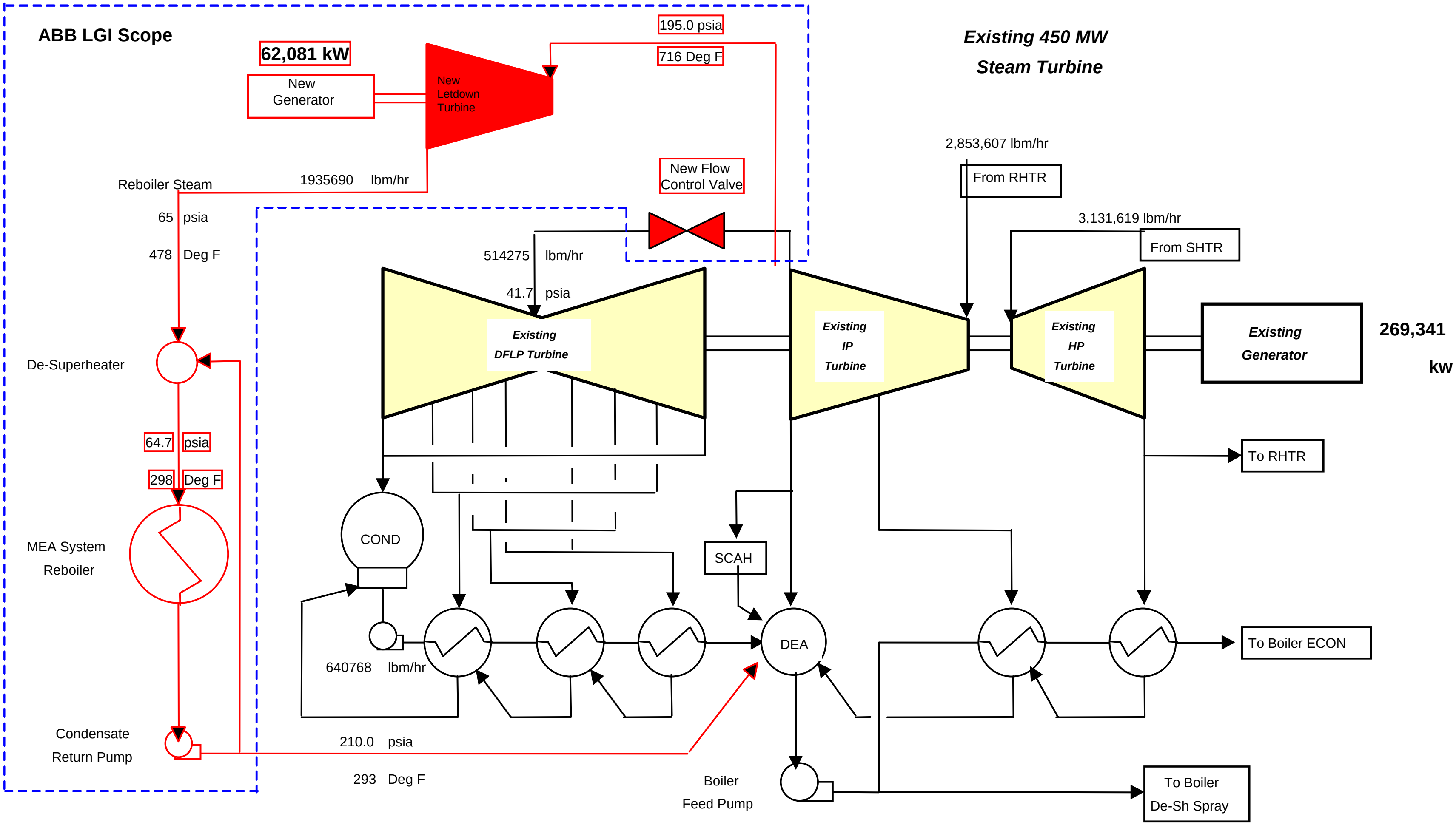
Steam Turbine Modifications

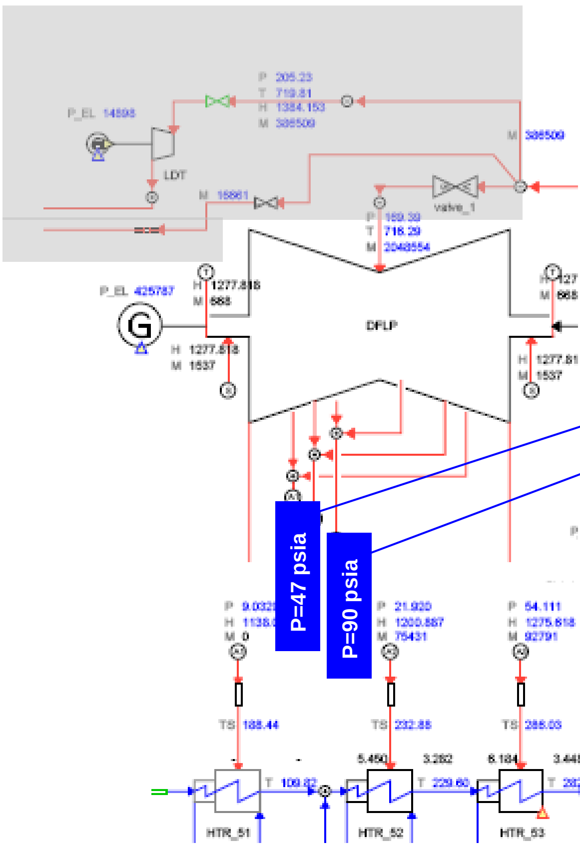
New Let Down Turbine

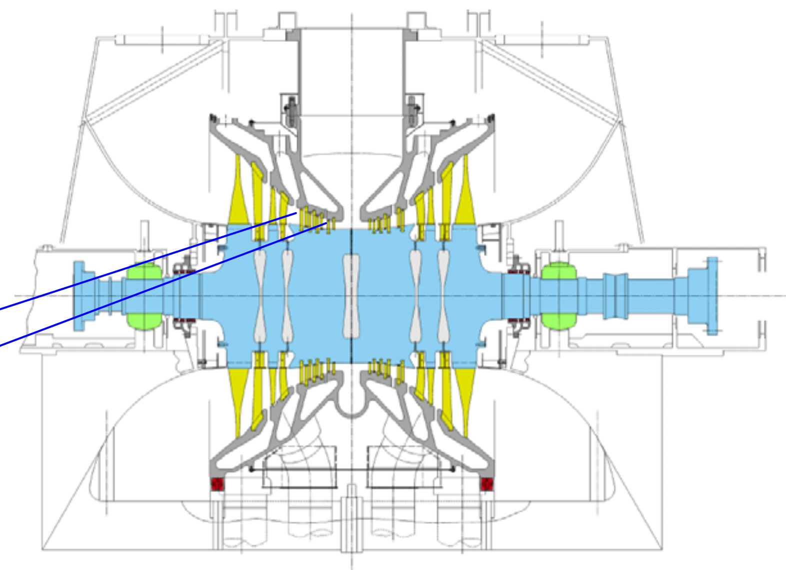


1. New LT output between 15 MW (30%) and 62 MW (90%)
2. EPC Cost ~ $10MM for each case

Steam Turbine Modifications
Alternatives to LDT?

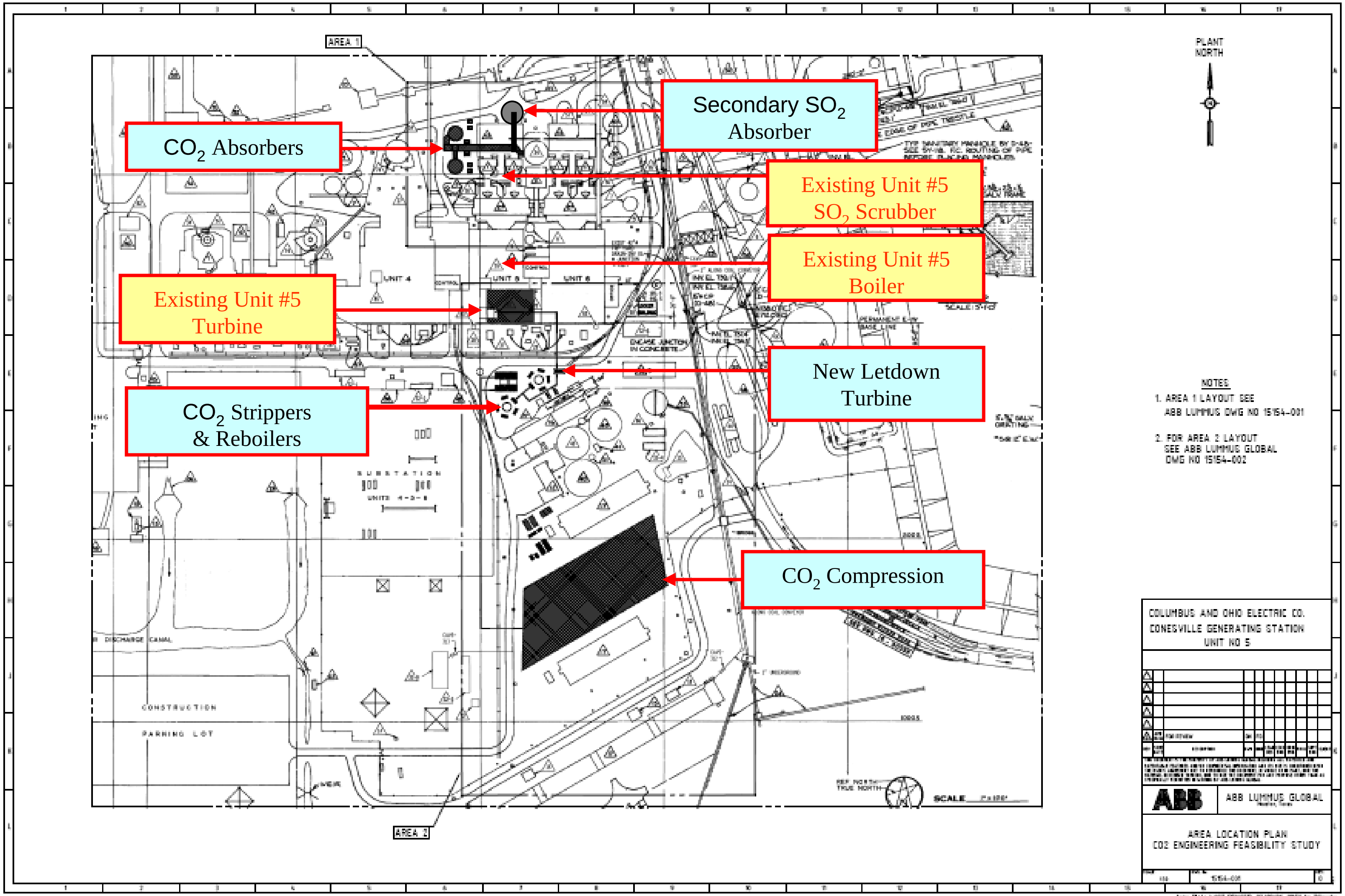
Retrofit solution for 30% Case





Potential solution by properly matching MEA plant requirements and retrofit design

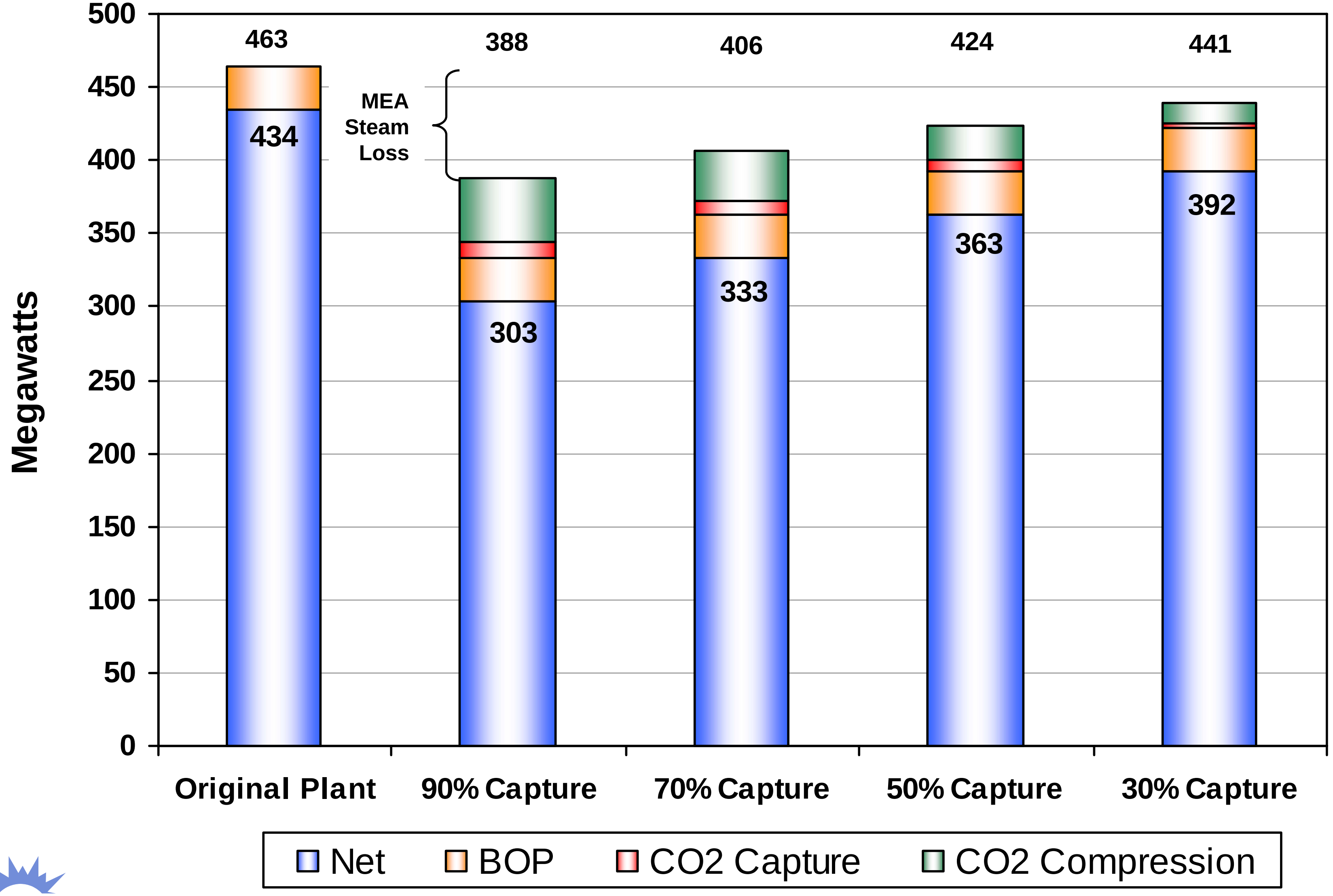
New Equipment Locations Identified



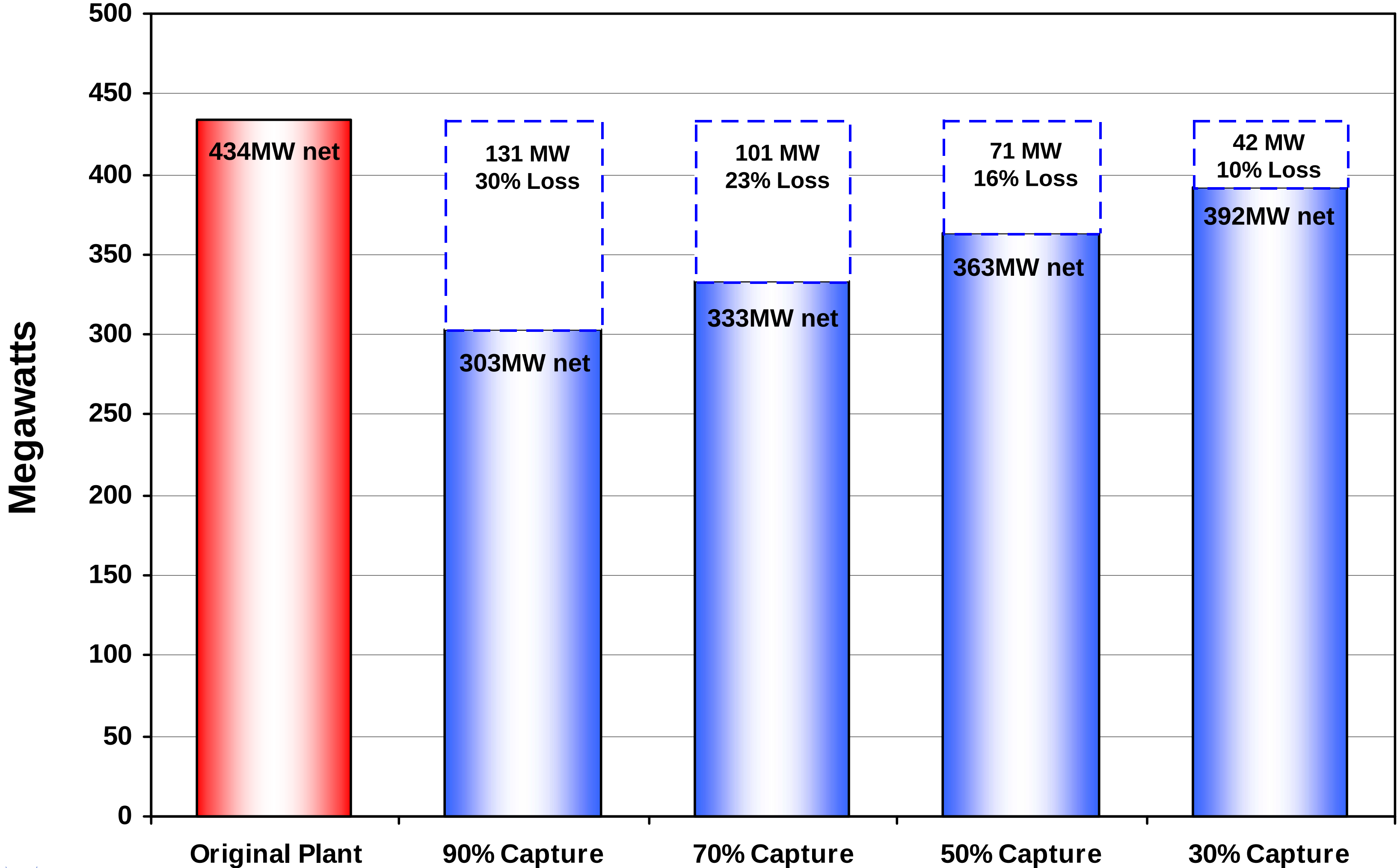
Plant Performance

- Plant Electrical Output
- Plant Auxiliary Power
- Plant Thermal Efficiency
- Plant CO_2 Emissions

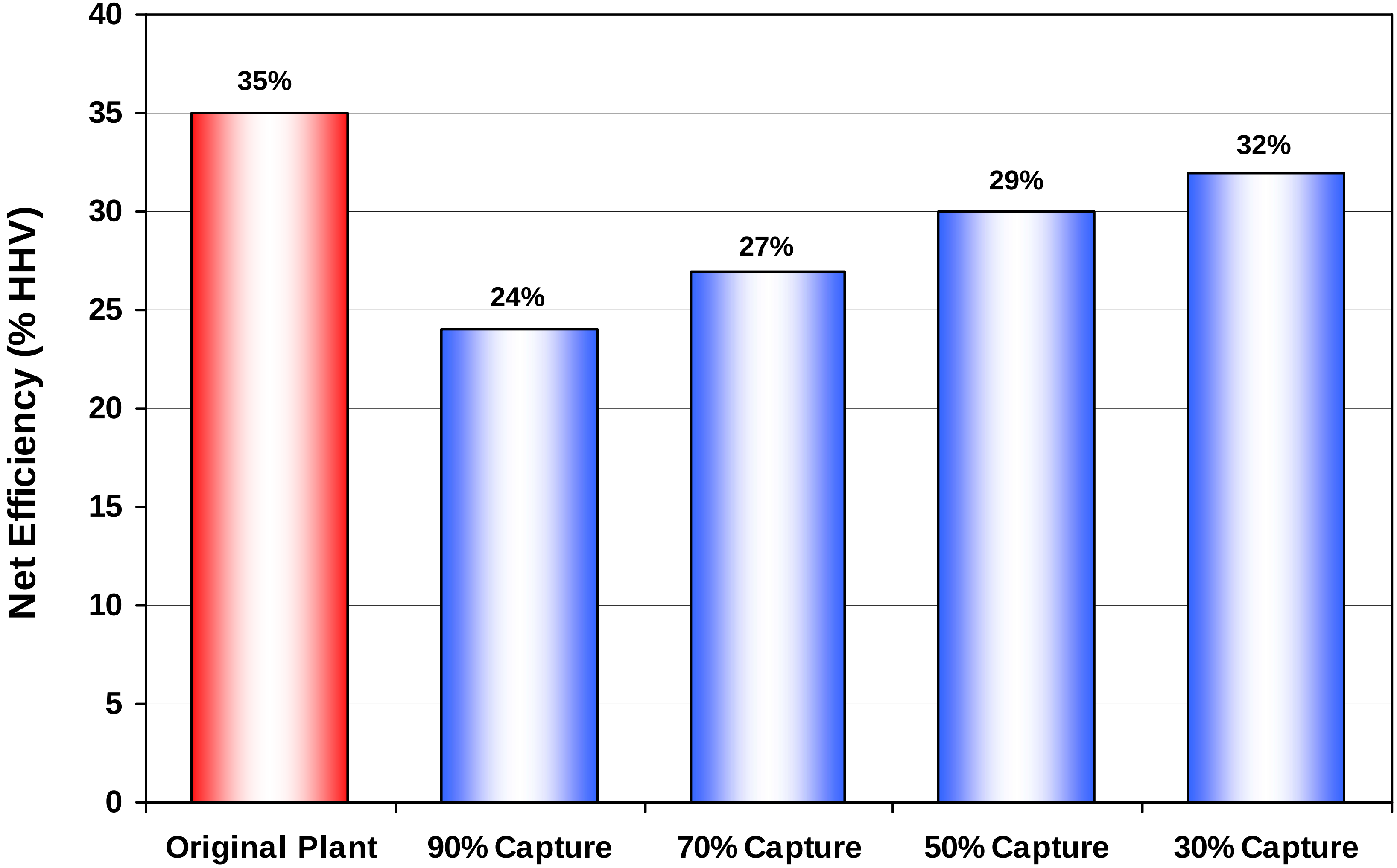
Power Output Distribution



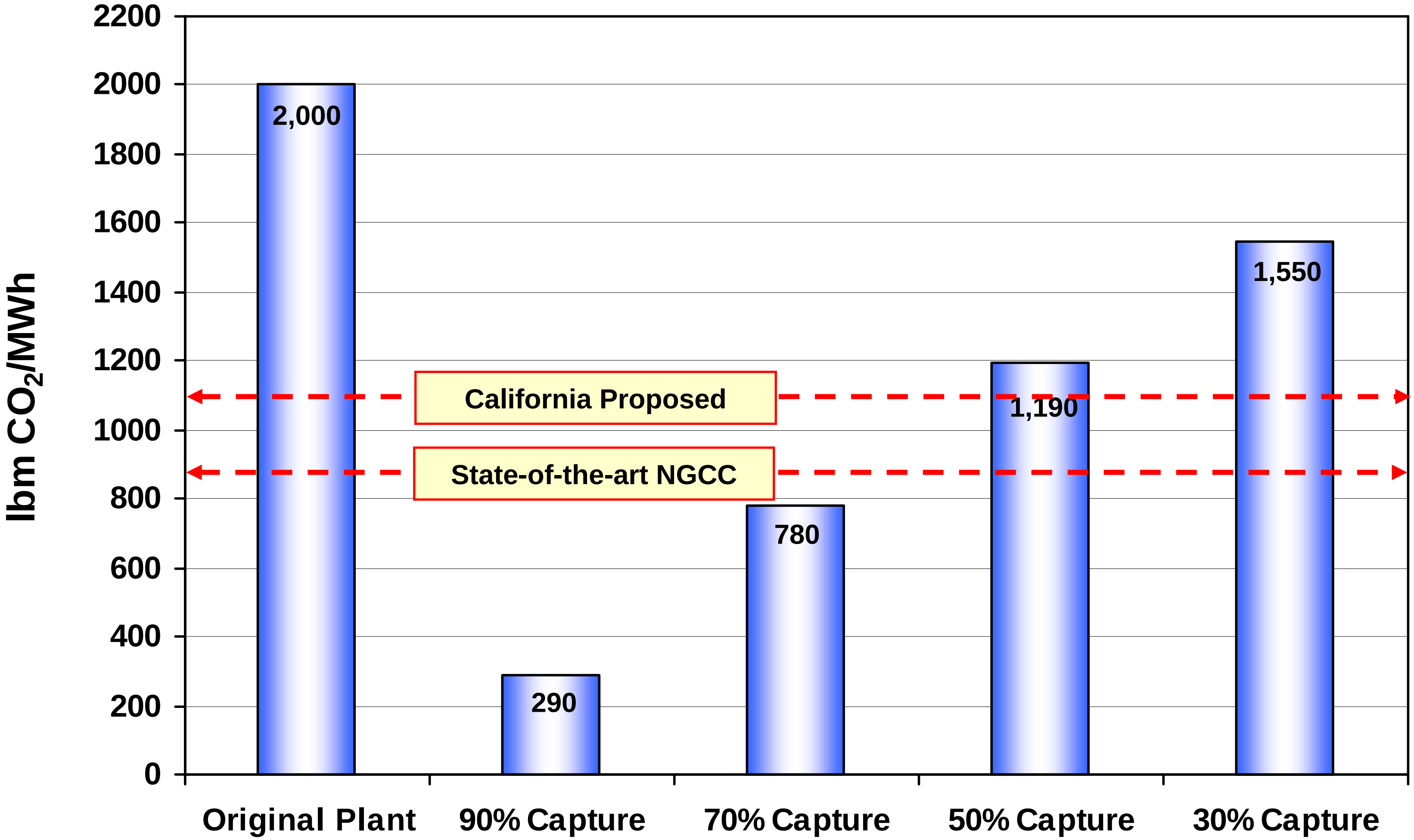
Base load (Net) Output Impact
Losses to Grid



Plant Thermal Efficiency
(HHV Basis)



CO_2 Emissions



Economics

- Capital Costs
- Incremental COE
- Mitigation Costs
- Sensitivity Analyses

Plant Retrofit Capital Costs

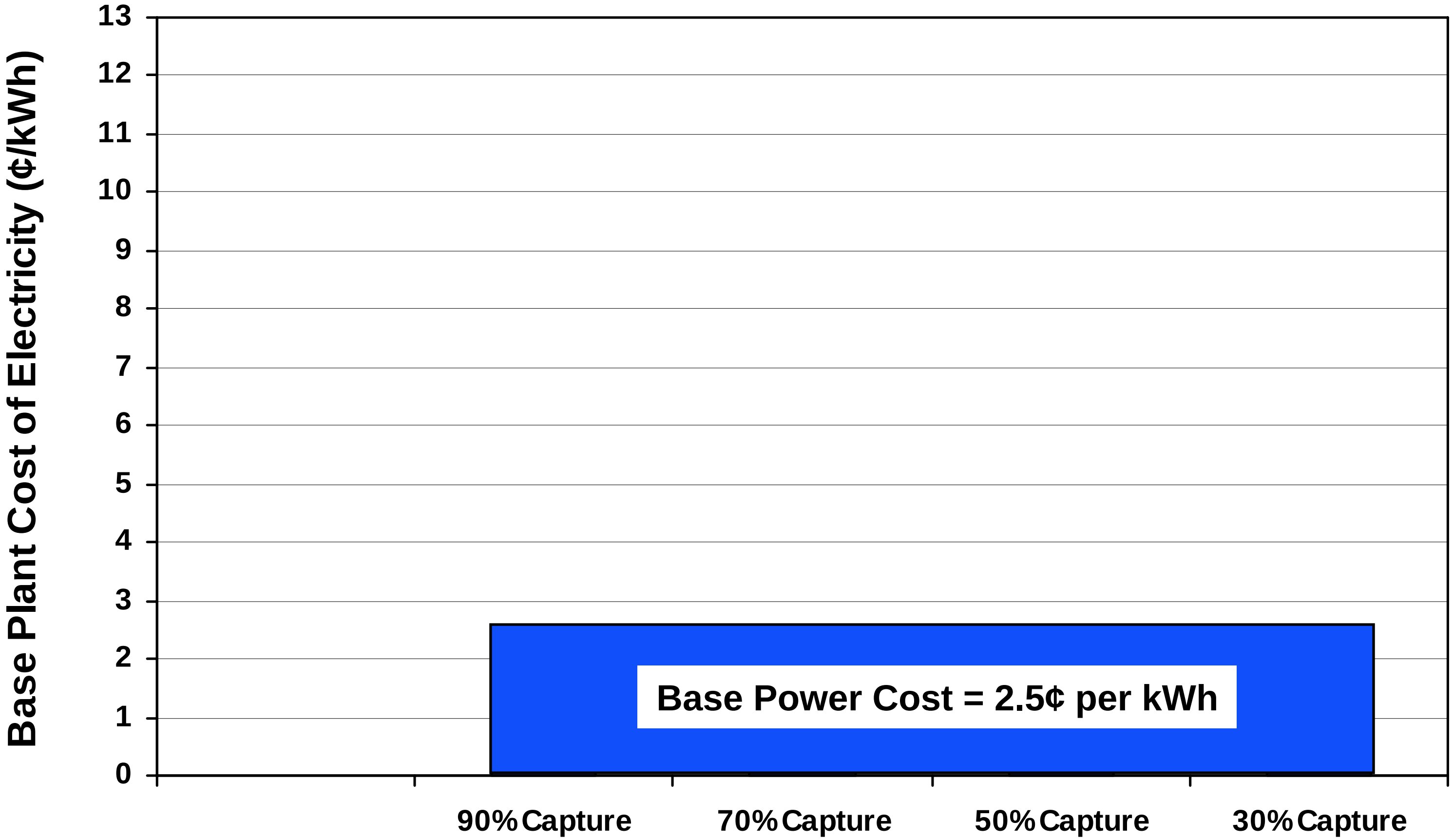
EPC Costs ($1000's)	2001	2007 Study			
% CO_2 Capture	**96**	**90**	**70**	**50**	**30**
CO_2 Capture & Compression	668,277	368,029	333,406	186,694	134,509
Flue Gas Desulfurization	22,265	22,265	22,265	22,265	22,265
Letdown Steam Turbine	10,516	9,800	9,400	8,900	8,500
Boiler Modifications	0	0	0	0	0
Total Retrofit Costs	**701,057**	**400,094**	**365,070**	**280,655**	**211,835**
New Net Output (kW)	251,634	303,317	333,245	362,945	392,067
$/kW-New Net Output	**2,786**	**1,319**	**1,095**	**773**	**540**
$/kW-Original Net Output*	**1,616**	**922**	**842**	**647**	**488**

*Original net output = 433,778 kW

53% Reduction in Incremental Capital Costs

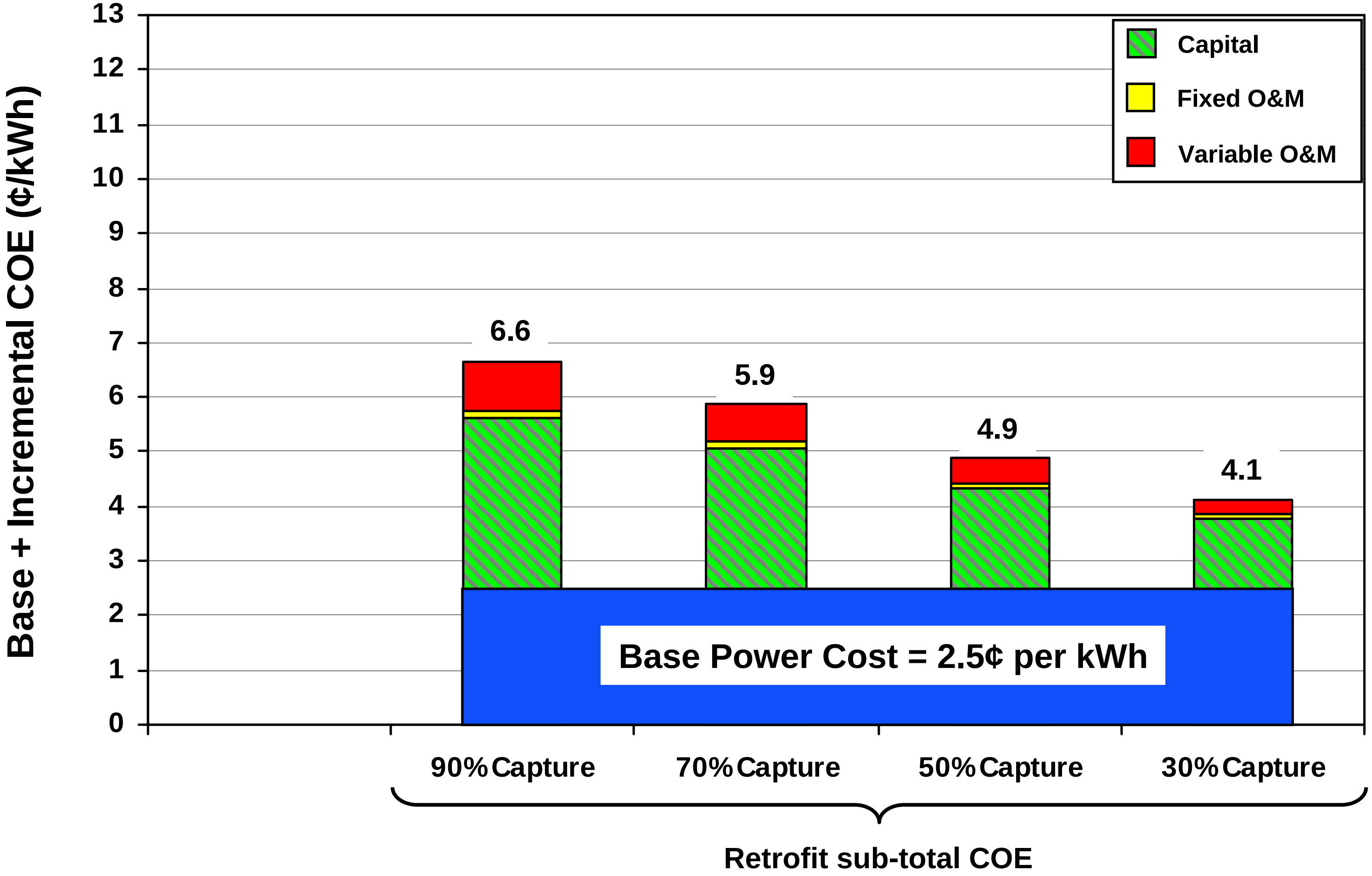
Note: Capital costs from 2001 study were escalated to 2006 dollars

Total Cost of Electricity



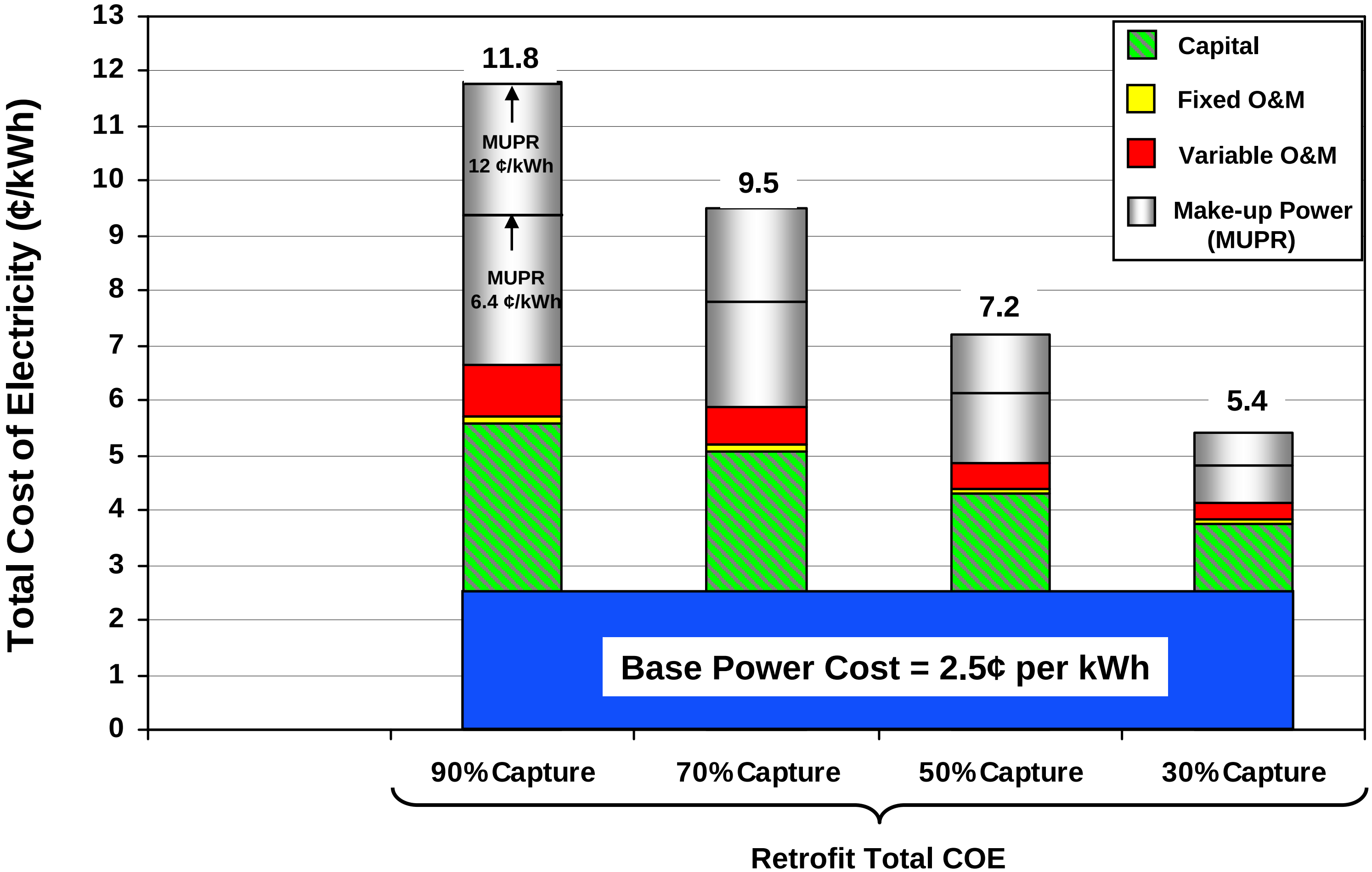
Note:
Base power plant cost for the existing plant obtained from Energy Velocity

Total Cost of Electricity



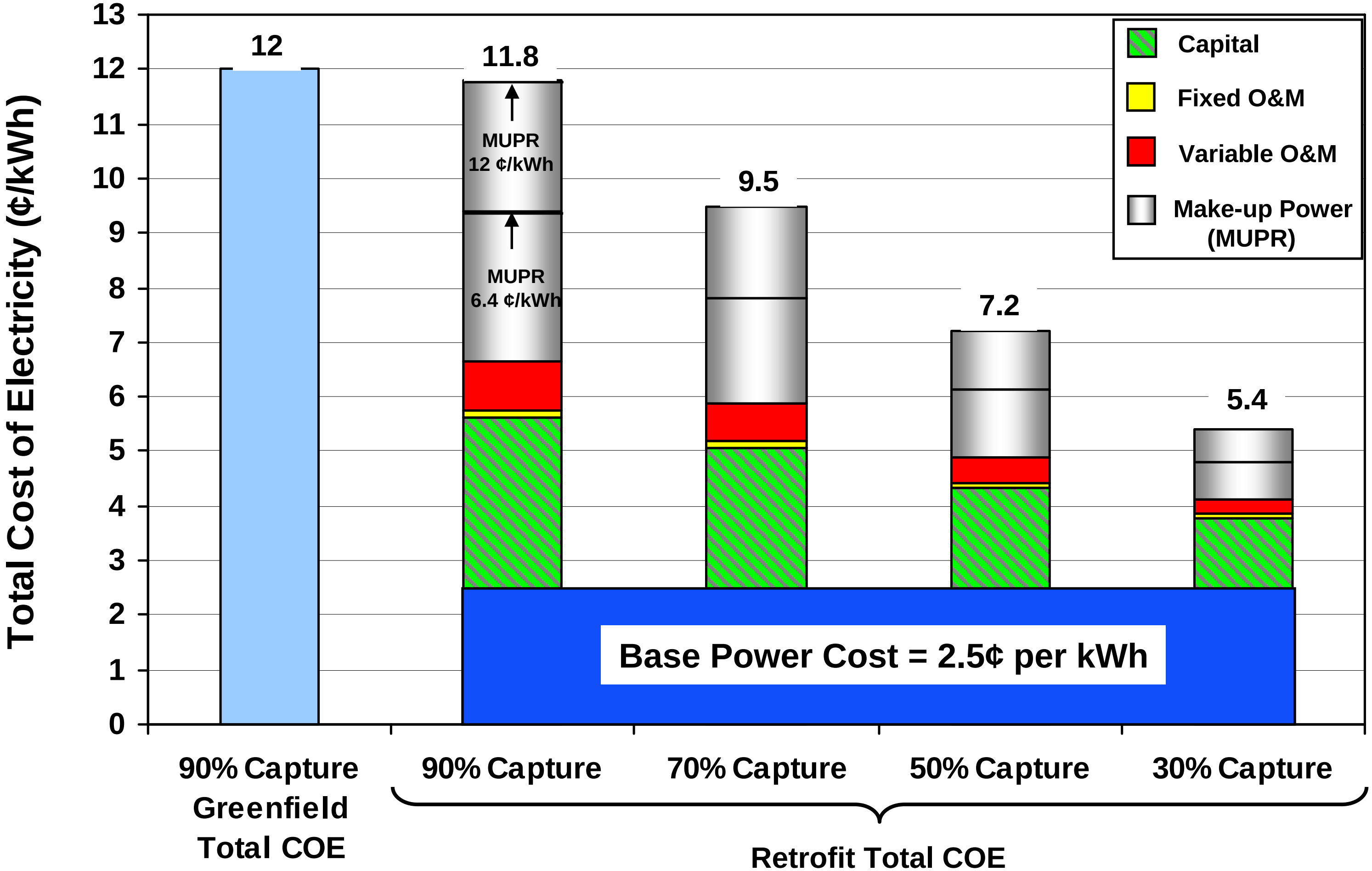
Notes:
COE is based off Total Plant Cost (Bare Erected Cost + Project and Process Contingencies); Does not include owner's costs
Base power plant cost for the existing plant obtained from Energy Velocity

Total Cost of Electricity



Notes:
Greenfield plant is a supercritical PC
COE is based off Total Plant Cost (Bare Erected Cost + Project and Process Contingencies); Does not include owner's costs
Retrofit power plant make-up power assessed between 6.40 and 12 ¢/kWh
Base power plant cost for the existing plant obtained from Energy Velocity

Total Cost of Electricity



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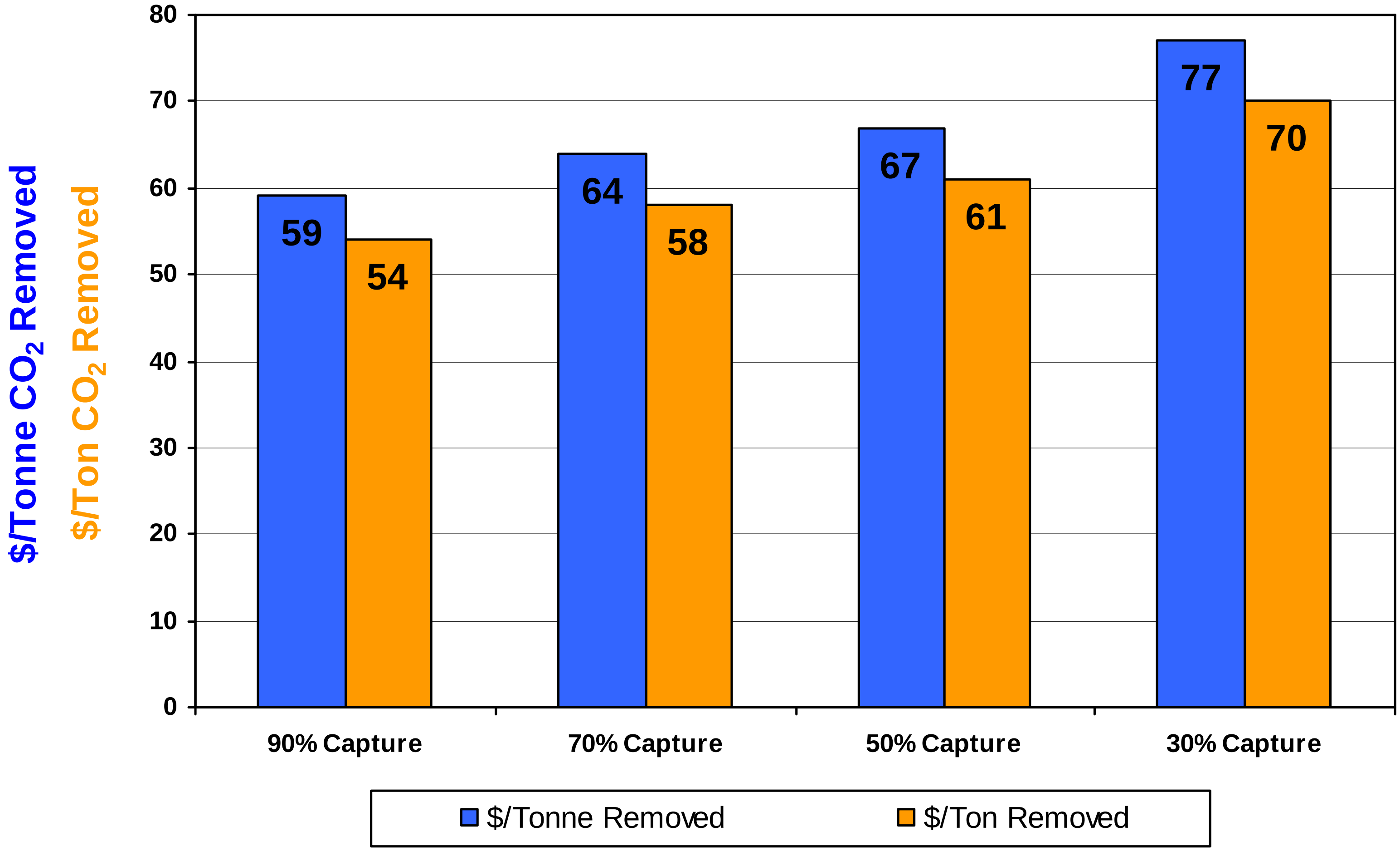
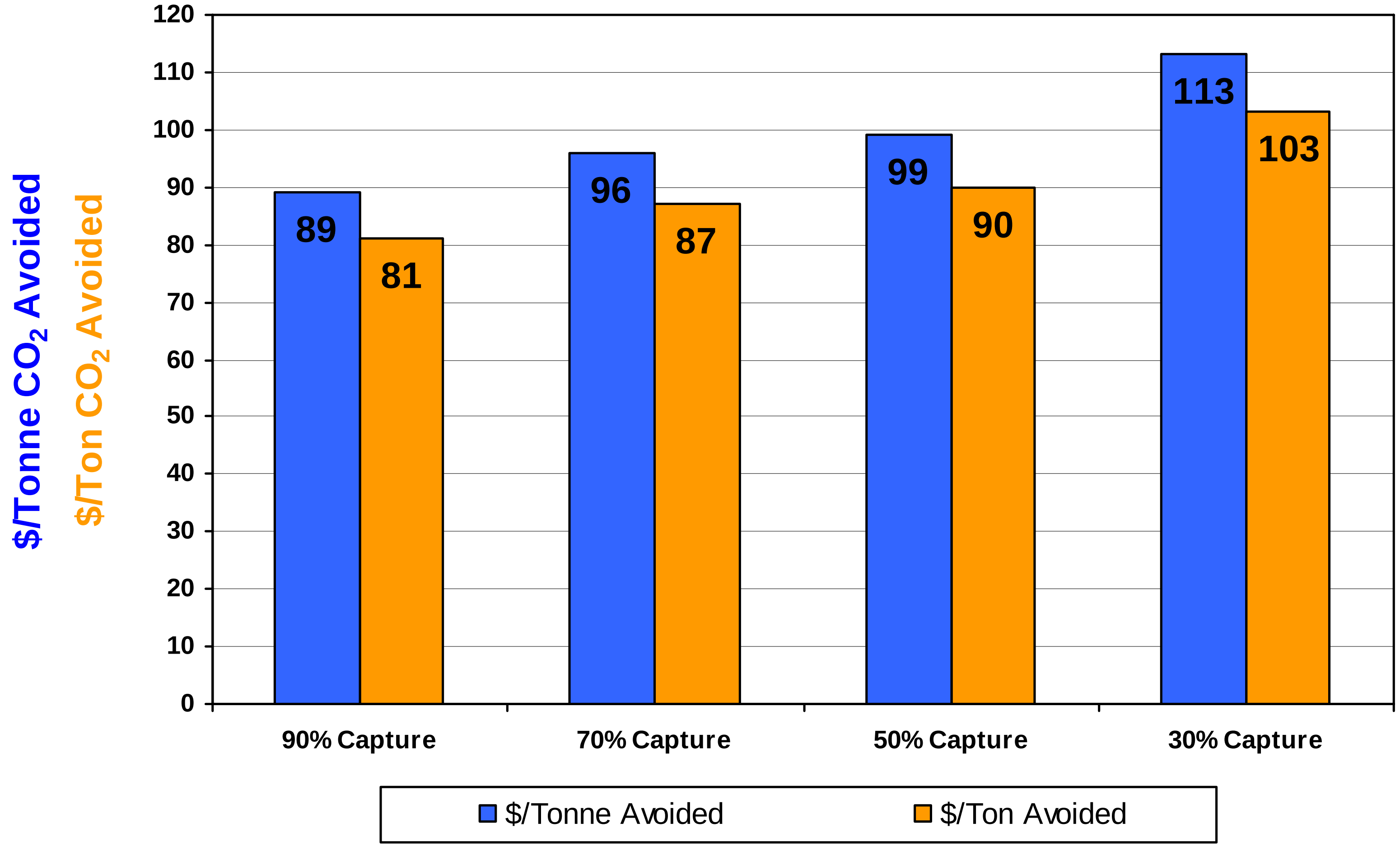
Economic Results

CO_2 Captured Cost



Economic Results

CO_2 Avoided Cost



Conclusions

1. No major technical barriers found to retrofit with current state-of-the-art scrubbing technology

2. Compared to the 2001 study, this study with an advanced amine (90% CO_2 Capture case) showed:
   - Marked improvement in energy penalty and reduction in cost

3. Near linear decrease in incremental COE with reduced CO_2 capture level

4. Sufficient results to answer various definitions of “optimal CO_2 capture” from existing plants

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Thank You!

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NETL Energy Analysis Link:

www.netl.doe.gov/energy-analyses