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IECM User Manual

DE-AC26-04NT41917

This document contains a new User Manual developed for the new Water Systems modules of the IECM. The previous User Manual for the remainder of the IECM follows the new Water Systems User Manual.

Water Systems

Water Systems

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Cooling System Configuration

This screen is only available for pulverized coal power plants. However, the option of **Cooling System** is available for all plant types. Inputs for configuration of the Cooling System are briefly introduced below.

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Cooling System- Configuration Plant Input Screen

- **Cooling System:** This option determines the cooling technology: "Once-Through", "Wet Cooling Tower", and "Air Cooled Condenser". The **default** technology is the **Once-Through** cooling system.
 - **Once-Through:** Cooling water is withdrawn from a natural waterbody, passed through the steam condenser and returned to the waterbody.
 - **Wet Cooling Tower:** Cooling water is recirculated through the wet tower and back to the condenser. The tower mainly relies on the latent heat of water evaporation to transfer waste heat to the atmosphere.
 - Air Cooled Condenser: The air cooled condenser utilizes the sensible heating of atmospheric air passed across finned-tube heat exchangers to reject heat.

Once-Through Water Systems Results

This screen is available for all plant types when the once-through cooling system is loaded.

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Once-Through- Cooling Water Result Screen

Cooling Water: This variable presents the amount of cooling water through the primary steam cycle plus auxiliary cooling.

Wet Cooling Tower Configuration

This screen is available for all plant types. Inputs for configuration of the Wet Cooling Tower are entered on the **Config** input screen.

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Wet Cooling Tower- Config. Input Screen

The parameters are described briefly below.

- Air Flow Draft Control Type: This option determines the type of air flow draft: "Natural" or "Forced". The "Natural" draft utilizes buoyancy to make natural rising of air through the tower, whereas the "Forced" draft uses the fan at the intake to force air through the tower. The choice of draft type has an effect on tower evaporation loss. Currently, only "Forced" draft type is available.
- Slip Stream Treatment System: This option determines whether a slip stream treatment system is loaded. The choice ("Yes" or "No") of a slip stream treatment system depends on site-specific quality of cooling water in the closed-loop recirculating system.
- Makeup Water Treatment System: This option determines whether a makeup water treatment system is needed. The choice ("Yes" or "No") of a makeup water treatment system depends on site-specific quality of makeup water for the cooling system.

Wet Cooling Tower Performance Inputs

This screen is available for all plant types. Inputs for performance of the Wet Cooling Tower technology are entered on the **Performance** input screen.

Each parameter is described briefly below.

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Wet Cooling Tower- Performance Input Screen

- Ambient Air Temp (Dry Bulb Avg.): This refers basically to the ambient air temperature measured by a thermometer. This input specifies annual average ambient temperature.
- Air Wet Bulb Temperature (Avg.): This refers to the temperature of air that is cooled adiabatically to saturation at a constant pressure by evaporation of water into it. That is calculated in terms of ambient dry bulb temperature and humidity. That is the lowest temperature that can be reached by evaporating water into the air.
- **Cooling Water Inlet Temperature:** This is the temperature of the cooling water entering the wet tower.
- **Cooling Water Temperature Drop:** This parameter specifies the temperature drop range of cooling water across the wet tower.
- **Cycles of Concentration:** That is a measure of the degree to which dissolved solids are being concentrated in the circulating water and is estimated in terms of concentration ratio of dissolved solids in the circulating versus makeup water. That is reversely related to the blowdown. Improving the quality of makeup water for the cooling system can increase the cycle of concentration and decrease the amount of tower blowdown.
- **Tower Drift Loss:** This parameter specifies a percent of the quantity of cooling water as drift loss.
- **Auxiliary Cooling Load:** This parameter specifies additional heat load on the auxiliary equipments and expressed as a percentage of the load on the primary steam cycle. The default value comes from the PISCES model.
- **Overdesign Factor:** This parameter overdesigns the wet tower size.

- **Slip Stream Inlet:** This parameter specifies the underflow as a percent of the quantity of cooling water. This option is only available when the Slip Stream Treatment System is loaded.
- **Slip Stream Underflow:** This parameter specifies the underflow as a percent of the quantity of slip stream. This option is only available when the Slip Stream Treatment System is loaded.
- **Cooling Makeup Underflow:** This parameter specifies the underflow as a percent of the quantity of entering water treated. This option is only available when the Makeup Water Treatment System is loaded.
- **Power Requirement:** This is the power needed to run the pumps and other equipments for the water cooling system. It is also referred to as a base plant energy penalty. In the PC power plants, it is expressed as a percentage of the gross plant capacity. In the IGCC plants, it is calculated based on the steam turbine power output and expressed as a scaled percentage of the total gross power outputs including the gas and steam turbines.

Wet Cooling Tower Retrofit Cost Inputs

This screen is available for all plant types. Inputs for capital costs of modifications to process areas to implement the Wet Cooling Tower are entered on the **Retrofit Cost** input screen for the Wet Cooling Tower system.

The retrofit cost factor of each process is a multiplicative cost adjustment which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

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Wet Cooling Tower- Retrofit Cost Input Screen

Each parameter is described briefly below.

Capital Cost Process Area

- **Cooling Tower Structure:** This area deals with the cooling tower and installation. The erected tower includes structure, fans, motors, gear boxes, fill, drift eliminators, etc.
- **Circulation Pumps:** This area deals with the circulating cooling water pumps.
- **Auxiliary Systems:** This area deals with a closed-loop process that utilizes a higher quality water to remove heat from ancillary equipments and transfers that heat to the main circulating cooling water system.
- **Piping:** This area deals with the circuiting cooling water piping. The piping system is equipped with butterfly isolation valves and all required expansion joints.
- **Makeup Water System:** This area deals with the capital equipments to provide makeup water for the cooling system.
- **Component Cooling Water System:** This area deals with the component cooling water system.
- Foundation & Structures: This area deals with the circulating water system foundation and structures.

Wet Cooling Tower Capital Cost Inputs

This screen is available for all plant types.

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Wet Cooling Tower-Capital Cost Input Screen

Each parameter is described briefly below.

- **Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).
- **General Facilities Capital (GFC):** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-

up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

- Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a wet cooling tower that has been paid off.

Wet Cooling Tower O&M Cost Inputs

This screen is available for all plant types.

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Wet Cooling Tower- O&M Cost Input Screen

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below:

Water Cost: This is the cost of water in dollars per thousand gallons.

- Waste Disposal Cost: This is the waste disposal cost for the wet tower.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks 6 weeks PTO) = 4.75 equiv. Shifts/day).
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Wet Cooling Tower Diagram

This screen is available for all plant type. The **Diagram** result screen displays an icon for the Wet Cooling Tower selected and values for major flows in and out of it.



Wet Cooling Tower- Diagram

Each result is described briefly below.

Cooling Water Entering Wet Tower

- **Water In:** The amount of recirculating cooling water entering the wet tower. That depends on the plant size, steam cycle heat rate and cooling water temperature drop range. That is the sum of cooling water through the main steam cycle, and amine-based carbon capture system if applicable.
- **Temperature In:** The temperature of recircualting cooling water entering the wet tower.

Cooling Water Exiting Wet Tower

Water Out: The amount of recirculating cooling water exiting the wet tower. That is equal to the amount of cooling water entering the wet tower based on water mass balance. That is the sum of cooling water

through the main steam cycle, and amine-based carbon capture system if applicable.

Temperature Out: The temperature of reciruclating cooling water exiting the wet tower. That is calculated in terms of the inlet cooling water temperature and cooling water temperature drop range.

Wet Tower Performance

- **Makeup Water:** The cooling tower operation is maintained by making up fresh water at the same rate as the water losses (evaporation, blowdown, and drift loss) from the tower.
- **Makeup Underflow:** This output gives the amount of wastes from cooling makeup water treatment system.
- **Evaporation:** In wet cooling towers, water has direct contact with ambient air and cooling is achieved mainly by the evaporation process in which some of the water leaves with the air. The evaporation process is the largest source of cooling tower water losses. That is estimated based on the mass and energy balance mode. Evaporation loss varies with meteorological conditions and displays a seasonal pattern.
- **Blowdown:** Because water evaporated in the cooling tower consists of pure water, the concentration of salts or other impurities will increase in the recirculating water. To avoid a high concentration and subsequent scaling of the surface within the tower, it is necessary to blow down a portion of the water that depends on the cycle of concentration and evaporation loss.
- **Drift Loss:** A relatively small amount of entrained water lost as fine droplets in the air discharge from a tower, which is frequently referred to as tower drift loss.
- **Basin Sludge:** This output specifies the amount of the basin sludge of the cooling tower system. That is an intermittent waste stream that contains collected soil, dust, and suspended solids in the tower basin.

Wet Cooling Tower – Cooling Water Diagram

This screen is available when the wet cooling tower is loaded.

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Wet Cooling Tower- Cooling Water Result Screen

Each result is described briefly below

Total Cooling: This variable presents the amount of cooling water through the main steam cycle plus auxiliary cooling.

Steam Cycle: This variable presents the amount of cooling water through the main steam cycle.

Wet Cooling Tower Capital Cost Results

This screen is available for all plant types. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the Wet Cooling Tower technology.

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		3	Auxiliary Syste	ems		0.281	2	3	Eng. & Hom	e Office Fee	s	2	840
		4	Piping			8.154	4	4	Project Cont	ingency Co	st	4	260
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Wet Cooling Tower-Capital Cost Result Screen

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Direct Capital Costs

Cooling Tower Structure: This area deals with the cost for the cooling tower and installation.

- **Circulation Pumps:** This area deals with the cost for the circulating cooling water pumps.
- **Auxiliary Systems:** This area deals with the cost for a closed-loop process that utilizes a higher quality water to remove heat from ancillary equipments and transfers that heat to the main circulating cooling water system.
- **Piping:** This area deals with the cost for the circuiting cooling water piping.
- **Makeup Water System:** This area deals with the cost for the capital equipments to provide makeup water for the cooling system.
- **Cooling Water System:** This area deals with the cost for the component cooling water system.
- **Foundation & Structures:** This area deals with the cost for the circulating water system foundation and structures.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. That is regressed as a function of the recirculating cooling water flow rate

based on the National Energy Technology Laboratory baseline studies for fossil fuel power plants (2007). The cooling tower used for cost estimation is a multi-cell wood frame counterflow mechanical draft cooling tower. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the wet cooling tower that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the wet cooling tower.

Wet Cooling Tower O&M Cost Results

This screen is available for all plant types. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the Wet Cooling Tower technology.

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Wet Cooling Tower- O&M Cost Result Screen

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

- **Disposal:** Total cost to dispose the collected tower waste solids and wastewater.
- **Electricity:** Cost of power consumption of the scrubber. This is a function of the gross plant capacity and the cooling system energy penalty performance input parameter.
- Water: This is the annual cost of the water used by the cooling system.
- **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-

hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Wet Cooling Tower Total Cost Results

This screen is available for all plant types. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the Wet Cooling Tower technology.

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Wet Cooling Tower- Total Cost Result Screen

Cost Component

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

- **Annual Fixed Cost**: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Air Cooled Condenser Configuration

This screen is available for all plant types. Inputs for configuration of the Air Cooled Condenser are entered on the **Config** input screen.

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Air Cooled Condenser- Config. Input Screen

The parameters are described briefly below.

- **Condenser Type:** This menu controls the configuration of the condenser. In practice, there are two condenser types (Single Row or Multiple Row). There is only a Multiple-Row condenser modeled in the current version.
- **Configuration:** This menu shows the geometry of the dry cooling system framework. An air cooled condenser is comprised of fin tube bundles grouped together in parallel and arranged typically in an A-frame configuration. The A-Frame configuration usually has an apex angle of 60° .

Air Cooled Condenser Performance Inputs

This screen is only available for all plant types. Inputs for performance of the Air Cooled Condenser technology are entered on the **Performance** input screen.

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Air Cooled Condenser- Performance Input Screen

The parameters are described briefly below.

- Ambient Air Temp (Dry Bulb Avg.): This refers basically to the ambient air temperature measured by a thermometer. This input specifies annual average ambient temperature.
- **Inlet Steam Temperature:** That is the temperature of exhaust steam entering the air cooled condenser system. That is calculated as a function of the steam turbine backpressure. The difference between inlet steam and ambient air temperatures significantly affects the performance and cost of the dry cooling system.
- **Fan Efficiency:** This parameter specifies the electricity efficiency of fan drive system. That is a percent of electrical power inputs to the fans.

- **Condenser Plot Area (per cell):** This parameter specifies the footprint or plot area of one cell. One cell typically consists of multiple condenser bundles and is served by a large axial flow fan located at the floor of each cell.
- **Turbine Back Pressure:** This parameter specifies the quantity of steam turbine backpressure. For the plant installed with a wet cooling system, the steam backpressure ranges from 1.5 to 2.0 inches of Mercury (inches Hg) whereas the steam backpressure for the plant installed with a dry cooling system ranges from 2.0 to 8.0 inches Hg. Turbine back pressure affects the steam cycle heat rate, and indirectly has an effect on the cooling system size when air cooled condensers are loaded.
- **Aux. Heat Exch. Load:** This parameter specifies additional heat load on the auxiliary condenser and is expressed as a percentage of the load on the primary condenser.
- Air Cooled Condenser Power Requirement: This parameter specifies the power needed to operate the big fans in the dry cooling system. It is also referred to as an energy penalty to the base plant. The electricity required for these big fans is estimated using the air cooled condenser performance model and is expressed as a percentage of the gross plant capacity. That is a function of the initial temperature difference between inlet steam and air and ambient pressure.

Air Cooled Condenser Retrofit Cost Inputs

This screen is only available for all plant types. Inputs for capital costs of modifications to process areas to implement the Air Cooled Condenser are entered on the **Retrofit Cost** input screen for the Air Cooled Condenser system.

The retrofit cost factor of each process is a multiplicative cost adjustment which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

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Air Cooled Condenser- Retrofit Cost Input Screen

The parameters are described briefly below.

Capital Cost Process Area

- **Condenser Structure:** This area deals with the air cooled condenser equipments including finned tube heat exchanger elements, fans and motors, ACC support structure, steam exhaust duct, piping and valves, air removal equipment and support for start-up, training, and testing. The erection and installation of the ACC at the site is also included in this area.
- **Steam Duct Support:** This area deals with steam duct support and column foundations.
- **Electrical & Control Equipment:** This area deals with fan, pump motor wiring and controls, etc.
- **Auxiliary Cooling:** That deals with separate fin-fan unit or others. Typically, that is 5% additional heat load.
- **Clearing System:** That area handles with cleaning finned tube surfaces. That is small but required at most sites.

Air Cooled Condenser Capital Cost Inputs

This screen is available for all plant types.

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	9	<u>C</u> onfigure	Plant		Set <u>P</u> arameters					<u>G</u> et Results				
C	Overall Plant Fuel Base <u>N</u> Ox Plant Control				<u>T</u> SP Control	<u>S</u> O2 Contro	ol	Mercury	C <u>O</u> 2 Captu	re V <u>a</u> l Syste	ter By- ems M	Prod. gmt St		
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	3	General Faci	lities Capit	al	%PFC	2		10.00		0.0	50.00	10.00		
	4	Engineering	& Home O	ffice Fees	%PFC	2		10.00		0.0	50.00	10.00		
	5	Project Cont	tingency C	ost	%PFC	;		15.00		0.0	100.0	15.00		
	6	Process Contingency Cost			%PFC	2		0.0		0.0	100.0	0.0		
	7	Royalty Fee:	s		%PFC	7		0.5000		0.0	10.00	0.5000		
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	9	Pre-P	roduction	<u>Costs</u>										
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			,											
	Proc	ess Type:	Air Coole	d Condens	er	Y		Costs are	III CON	stant 2007	dellars.			

Air Cooled Condenser- Capital Cost Input Screen

Each parameter is described briefly below.

- **Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).
- **General Facilities Capital (GFC):** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-

up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

- Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a dry cooling system that has been paid off.

Air Cooled Condenser O&M Cost Inputs

This screen is available for all plant types.

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Ove <u>r</u> all Plant	Fuel Base NOx Plant Contro	1 Control Cor	D2 ntro1	<u>M</u> ercury	C <u>O</u> 2 Captur	W <u>s</u> Syst	ter By- ems M	Prod. gmt				
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1	Bulk Reagent Storage Time	daws		60.00		0.0	120.0	60.00				
3	DominordBoundardBo 1700			00.00		0.0	120.0	00.00				
4	Waste Disposal Cost	\$/ton		0.0		0.0	10.00	calc				
5	Electricity Price (Base Plant)	\$/MWh		41.36		0.0	200.0	calc				
6												
7	Number of Operating Jobs	jobs/shift		2.000		0.0	30.00	2.000				
8	Number of Operating Shifts	shifts/day		4.750		0.0	10.00	4.750				
9	Operating Labor Rate	\$/hr		33.00		0.0	100.0	33.00				
10												
11	Total Maintenance Cost	%TPC		1.500		0.0	10.00	1.500				
12	Maint. Cost Allocated to Labor	% total		40.00		0.0	100.0	40.00				
13	Administrative & Support Cost	% total labor		30.00		0.0	100.0	30.00				
14												
15												
10												
17			+		+							
Proc	ess Type: Air Cooled Conde	nser		Costs are	e in Con	stant 200'	7 dollars.	1				

Air Cooled Condenser- O&M Cost Input Screen

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below:

Waste Disposal Cost: This is the waste disposal cost for the wet tower.

- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks 6 weeks PTO) = 4.75 equiv. Shifts/day).
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Air Cooled Condenser Diagram

This screen is available for all plant type. The Diagram result screen displays an icon for the Air Cooled Condenser selected and values for major flows in and out of it and its size.



Air Cooled Condenser- Diagram

Each result is described briefly below

- **Number of Cells:** Number of cells in the dry cooling system. Each cell has eight heat exchanger bundles in the default. The heat exchanger bundle consists of two-row staggered plat-finned flat tubes.
- **Footprint Area:** The plot area of the dry cooling system. That is a function of initial temperature difference between inlet steam and air and ambient pressure.
- **Steam In:** The total mass flow rate of the exhaust steam. That depends on the plant size and steam cycle heat rate.
- **Steam Temperature:** The temperature of exhaust steam entering the air cooled condensers. That is empirically estimated in terms of the steam turbine back pressure.
- **Initial Temp. Diff.:** That is the temperature difference between inlet steam and steam of the dry cooling system. This variable significantly affects the performance and cost of the dry cooling system.

Air Cooled Condenser Capital Cost Results

This screen is available for all plant types. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the Air Cooled Condenser technology.

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8														
			Air Cooled Condenser Process Area Costs	Capital Cost (M\$)		Air Cooled Condenser Plant Costs	Capital Cost (M\$)							
P		1	Condenser Structure	67.02	1	Process Facilities Capital	76.91							
		2	Sream Duct Support	0.4221	2	General Facilities Capital	7.691							
-		3	Electrical & Control Equipment	2.078	3	Eng. & Home Office Fees	7.691							
		4	Auxiliary Cooling	6.814	4	Project Contingency Cost	11.54							
8		5	Clearing System	0.5766	5	Process Contingency Cost	0.0							
▶?		6			6	Interest Charges (AFUDC)	11.06							
		7			7	Royalty Fees	0.3845							
		8	Process Facilities Capital	76.91	8	Preproduction (Startup) Cost	2.800							
		9			9	Inventory (Working) Capital	0.5191							
		10			10	Total Capital Requirement (TCR)	118.6							
		11			11									
		12			12									
		13			13									
		14			14									
		15			15	Effective TCR	118.6							
		Pro	cess Type: Air Cooled Condenser	•		Costs are in Constant 2007 dollars.								
	L		1. Diagram <u>2. Capital Cost</u>	. O&M Cost	4	, Total Cost								

Air-Cooled Condenser- Capital Cost Result Screen

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Direct Capital Costs

- **Condenser Structure:** This area deals with the cost of air cooled condenser equipments, erection and installation of the air cooled condensers at the site. The cost of the ACC equipments is estimated as a function of initial temperature difference between inlet steam and air based on the cost data estimated by Electric Power Research Institute. The erection accounted for approximately 30% of the sum of the equipment and erection cost, which is equivalent to about 43% of the ACC equipment cost.
- **Scream Duct Support:** This area deals with the cost of steam duct support and column foundations.
- **Electrical & Control Equipment:** This area deals with the cost of fan, pump motor wiring and controls, etc.
- **Auxiliary Cooling:** That deals with the cost of auxiliary cooling including separate fin-fan unit or others.
- **Clearing System:** That deals with the cost of clearing finned tube surfaces.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. That highly depends on the initial temperature difference between inlet steam and air. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the dry cooling system that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the dry cooling system.

Air Cooled Condenser O&M Cost Results

This screen is available for all plant types. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the Air Cooled Condenser technology.

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		4								4	Admin. & Su	pport Labo	r	0.	3926
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Air Cooled Condenser- O&M Cost Result Screen

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Disposal: Total cost to dispose the collected cleaning wastes.

- **Electricity:** Cost of power consumption of the scrubber. This is a function of the gross plant capacity and the cooling system energy penalty performance input parameter.
- **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Air Cooled Condenser Total Cost Results

This screen is available for all plant types. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the Air Cooled Condenser technology.

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		2	Annus	al Variable C	ost		3.388	1.103	3 0.0	14.37	
		3	Total A	Annual O&I	M Cost		6.024	1.961	0.0	25.55	
		4	Annua	alized Capits	1 Cost		17.55	5.713	8 0.0	74.45	
2		5	Total I	Levelized A:	nnual Cost		23.57	7.673	8 0.0	100.0	
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Air Cooled Condenser- Total Cost Result Screen

Cost Component

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

- **Annual Fixed Cost**: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Makeup Water System Results

This screen is only available for pulverized coal power plants. Major outputs are briefly described below.

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	Overall Fuel Base HOR TSP SO2 Mercury CQ2 Water By Plant Control Control Control Control Systems M	-Prod. Stac <u>k</u> Igmt Stac <u>k</u>
	→ Boiler Makeup (tons/hr)	163.3
	(No cooling tower)	
↓ ↑ № №	Plant Inlet (tons/hr) 386.5	0.0 0.0
	(No Combustion NOx Con	.trol)
	→ FGD Makeup (tons/hr)	176.2
	CCS Makeup (tons/hr)	47.05
	Process Type: 1. Makeup Water	
	1. Diagram	

Makeup Water Result Screen

Plant Inlet: this variable presents the total amount of makeup water required by the plant for boiler, cooling system, bottom ash sluice, fly ash sluice, FGD, and carbon capture system if applicable.

Boiler Makeup: This variable presents the amount of makeup water for the main steam cycle to supplement boiler blowdown and

miscellaneous steam losses, which mainly depends on the boiler blowdown rate.

- **Cooling Makeup:** This variable presents the amount of makeup water for the cooling system. There is no makeup water required for oncethrough and air cooled condenser systems. For the wet cooling tower, the makeup water is required to supplement the evaporation, blowdown and drift losses.
- **Bot. Ash Sluice:** This variable presents the amount of makeup water used for sluicing bottom ash that is collected at the bottom of the boiler. In a wet sluicing system, bottom ash is sluiced with water and transported to a bottom ash pond where the ash settles in the pond. There may no need of makeup water to sluice bottom ash as the blowdown from the wet tower and bottom ash pond overflow can be reused as sluice water.
- **CE-ESP Sluice:** This variable presents the amount of makeup water used for sluicing fly ash that is entrained in the flue gas and removed by air pollution control system equipment such as ESP. There may no need of makeup water to sluice fly ash as the blowdown from the wet tower and bottom ash pond overflow can be reused as sluice water.
- **FGD Makeup:** The variable presents the amount of makeup water needed to replace the evaporated water in the reagent sluice circulation stream.
- **CCS Makeup:** The variable presents the amount of makeup water needed to replace the loss from contact cooler evaporation, dilute the makeup MEA, and supplement the reclaimer loss when amine-based capture system is used.

Water Consumption Results

This screen is only available for pulverized coal power plants. This screen summarizes water consumption across the entire plant. Major outputs are briefly described below.

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\$\$ >> @ @ } ● ● ??	Water Consump. (tons/hr) 1712 -		 FGD Evaporation (tons/hr) 177.6 Wet Tower Evap. (tons/hr) 1531 CCS Evaporation (tons/hr) 3.621
	<u>l. Diagram</u>		

Water Consumption Result Screen

- **Water Consumption:** This variable presents the total amount of water consumed across the entire plant including associated environmental control technologies.
- **FGD Evaporation:** This variable presents the amount of evaporation water in FGD when it is loaded.
- Wet Tower Evap.: This variable presents the amount of evaporation and drift losses in the wet tower when the wet cooling tower system is loaded.
- **CCS Evaporation:** This variable presents the amount of evaporation loss in direct contact cooler when the amine-based capture system is loaded.

Integrated Environmental Control Model

User Manual

Carnegie Mellon University


This manual was produced using ComponentOne Doc-To-Help.TM

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Introduction

The Integrated Environmental Control Model

This Integrated Environmental Control Model with Carbon Sequestration (IECM-cs) and Interface were developed for the <u>U. S. Department of Energy</u>'s <u>National Energy</u> <u>Technology Laboratory</u> (NETL), formerly known as the Federal Energy Technology Center (FETC), under contracts No. DE-AC22-92PC91346 and <u>DE-AC21-92MC29094</u>.

Purpose

The product of this work is a desktop computer model that allows different technology options to be evaluated systematically at the level of an individual plant or facility. The model takes into account not only avoided carbon emissions, but also the impacts on multi-pollutant emissions, plant-level resource requirements, costs (capital, operating, and maintenance), and net plant efficiency.

In addition, uncertainties and technological risks also can be explicitly characterized. The modeling framework is designed to support a variety of technology assessment and strategic planning activities by DOE and other organizations.

The model currently includes four types of fossil fuel power plants: a pulverized coal (PC) plant, a natural gas-fired combined cycle (NGCC) plant, a coal-based integrated gasification combined cycle (IGCC) plant, and an oxyfuel combustion plant. Each plant can be modeled with or without CO2 capture and storage. The IECM-cs can thus be employed to quantify the costs and emission reduction benefits of CCS for a particular system or to identify the most cost-effective option for a given application.

This model also can be used to quantify the benefits of technology R&D and to identify advanced technology options having the highest potential payoffs.

A Graphical User Interface (GUI) facilitates the configuration of the technologies, entry of data, and retrieval of results.

System Requirements

The current model requires the following configuration:

- Intel-based computer running Windows 98 (or better) or Windows NT 4.0 (or better) operating system
- Pentium Processor

- any SVGA (or better) display—at a resolution of 800x600 (or more) pixels¹
- at least 40 Megabytes of free hard disk space
- at least 128 Megabytes of total memory

Uncertainty Features

The ability to characterize uncertainties explicitly is a feature unique to this model. As many as one hundred input parameters can be assigned probability distributions. When input parameters are uncertain, an uncertainty distribution of results is returned. Such result distributions give the *likelihood* of a particular value, in contrast to conventional single-value estimates.

The model can run using single deterministic values or uncertainty distributions. The conventional deterministic form using single values for all input parameters and results may be used, or probabilistic analyses may be run—for instance, to analyze advanced technology costs (see <u>Appendix A</u> for more details).

Software Used in Development

The underlying engineering models are written in Intel® Visual Fortran. Fortran runtime libraries are included with the IECM Interface software. This language provides the flexibility to configure many various power plant designs while also providing the power to conduct probabilistic analyses.

All databases are in Microsoft[®] Access format and may be viewed in Access, as long as they are not changed. This format is a software industry standard and facilitates sharing and updating of information.

To simplify the use of the model, a Graphical User Interface (GUI) has been added. The interface eliminates the need to master the underlying commands normally required for model operation. The interface is written in Microsoft® Visual C++, a standard software development tool for the Windows environment. Visual C++ runtime libraries are included with the IECM Model software and do not need to be licensed separately.

Wise for Windows Installer was used to generate full installer programs. This product was chosen based on its flexibility and its support of Visual Basic runtime libraries and Microsoft Data Access Components (MDAC)². The Visual Basic runtime libraries provide the support needed to run the database file compactor program provided with the IECM. MDAC provides the software support needed to link Microsoft® Access data files to the IECM interface program. Wise for Windows Installer provides the VB and MDAC installation as an option, rather than forcing the user to download it from Microsoft and install it prior to installing the IECM.

¹ Smaller screen resolution results in the interface screens being scaled smaller. The taskbar, part of the Windows operating system, reduces the useable resolution of the screen if it is always visible. This may force the IECM interface to be scaled down slightly. To avoid this situation, select the "Auto Hide" option of the Taskbar properties in Windows.

 $^{^{2}}$ The current version of MDAC is 2.8. This is installed with the full installer for the IECM. Any update installers provided for upgrading the IECM from a previous version to the current version do not upgrade MDAC unless the user updates MDAC separately.

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User Documentation and Help

User Manual

The *User Manual* gives further information on both the interface and the underlying model. It provides detailed descriptions of plant configurations, parameter settings, and result screens. It also describes technical details behind the model's operation and includes an introduction to uncertainty analysis.

Technical Manuals

The *Technical manuals* are detailed engineering descriptions of the technologies and costing assumptions used in the IECM. These manuals are not provided by default with the IECM software; however, they can be downloaded with any web browser from http://www.iecm-online.com.

Online Help

Online help is provided via a Windows Help File containing the full text of the *User Manual*.

Accessing the IECM Help file:

If you are not running the IECM interface, click the **Help** icon inside the IECM folder on the **Start** menu. This opens the help file to the table of contents.

If you are running the IECM interface, do any one of the following:

- Press the **F1** key. The IECM supports context-sensitive help and will open the help file to the topic associated with the item or screen you are viewing.
- Pull down the **Help** menu at the top of the IECM window. Select **Help Topics**. This opens the help file to the table of contents.
- Click the **Context-Sensitive Help** icon on the toolbar on the left side of the IECM window. The IECM supports context-sensitive help and will open the help file to the topic associated with the item or screen you are viewing.
- Click the **Help Topics** icon on the toolbar on the left side of the IECM window. This opens the help file to the table of contents. If this method does not work, try one of the other options above.

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🔷 📎 Air Preheater	
🔷 陝 In-Furnace Controls	
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<u>O</u> pen <u>P</u> rint	Cancel

The IECM Help File Contents window will display.

The IECM Help File Topics Window

Installing the Model

Installation Options

Normal installation is described in *Getting Started*. This section addresses installation from a network drive or the worldwide web. This section also describes advanced features of the installation program and the files installed.

Local and Network Installation

The Setup program can be run from a local hard drive or a network server. Installing from a hard drive eases the burden of sharing one IECM compact disk (CD) between multiple users. Installing from a network server simplifies the process of installing the entire package on a series of personal computers connected to the network. However, both methods require some familiarity with creating and finding folders and sub-directories on a network hard drive.

NOTE:

You may also install the interface to a network server. All files will be loaded to the server except the shortcut in the start menu of the local personal computer. The interface will run from the server and all sessions will be saved to the network drive, meaning that others with access to the network drive may change or delete them. Installation to a network server is not currently supported.

Installing the IECM from a Local Hard Drive

To install from a local hard drive, copy the SETUP.EXE installer program from the IECM compact disk (CD) disk into one sub-directory or folder on your personal hard drive.

- 1. On the personal computer, click the Start button.
- 2. Choose **<u>R</u>un...** from the Start menu.
- 3. Type "X:\XXX\Media\SETUP.EXE" where "X:\XXX\" is the drive and directory on your local hard drive to which you copied the files.

The Installation Program will begin. Follow the instructions on the screen.

If you receive an error message while running Setup, restart your computer and run the installation program again. If Setup still returns an error message, call Technical Support.

Installing the IECM from a Network

To install from a network hard drive:

- 1. Copy the contents of the IECM compact disk (CD) disk into one subdirectory or folder on a network hard drive.
- 2. On the personal computer, click the Start button.
- 3. Choose **<u>R</u>un**... from the Start menu.
- 4. Type "X:\XXX\Media\SETUP.EXE" where "X:\XXX\" is the drive and directory on the network hard drive to which you copied the files.

The Installation Program will begin. Follow the instructions on the screen.

If you receive an error message while running Setup, restart your computer and run the installation program again. If Setup still returns an error message, call Technical Support

Internet Installation

The contents of the IECM CD-ROM are also available on the worldwide web (www.iecm-online.com). The media, documentation and various text files can be downloaded to your local computer or network hard drive.



www.iecm-online.com Home Page

Downloading the IECM from the internet.

To download the install software to your computer:

- 1. Open a web browser program (e.g., Internet Explorer or Netscape).
- In the "Address" line of the browser, type the following <u>http://www.iecm-online.com/iecm_dl.com</u>. You will see the iecmdownload page.



www.iecm-online.com Download Page

- 3. Click the text on the left labeled **Download IECM**.
- 4. Click on the blue button labeled **Download IECM**. A dialog box will appear.



File download dialog box; save the program to disk

5. Click on the **Save** button.

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Save file dialog box; use this to select the location to save the program

6. Choose a location to save the setup file and click the "Save" button.

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	Open Open Folder Cancel						

File download progress indicator

The download will begin. Once it is finished, you can proceed to install the IECM software. If you receive an error message while running the install program, restart your computer and run the installation program again. If it still returns an error message, contact <u>Technical Support</u>

Installing the IECM from the internet

To install the software to from the internet directly onto your computer:

- 1. Open a web browser program (e.g., Internet Explorer or Netscape).
- In the "Address" line of the browser, type the following <u>http://www.iecm-online.com/iecm_dl.html</u>. You will see the iecmdownload page.



www.iecm-online.com Download Page

3. Click on the blue button labeled **Download IECM**. A dialog box will appear.

File Download - Security Warning						
Do you	u want to run or save this file?					
	Name: IECM_520.exe Type: Application, 30.9MB From: www.iecm-online.com					
	<u>R</u> un <u>S</u> ave <u>Cancel</u>					
While files from the Internet can be useful, this file type can potentially harm your computer. If you do not trust the source, do not run or save this software. <u>What's the risk?</u>						

File download dialog box; run the program directly

4. Click on the **Run** button.

The installer program will download to a temporary location on your hard drive. Once it is finished, the installer program will automatically proceed to install the IECM software. If you receive an error message while running the install program, restart your computer and run the installation program again. If it still returns an error message, contact Technical Support. Once the installer program is completed, it will be deleted from the temporary location on your hard drive.

Files Added by Install

This section provides a full list and short description of the files installed by the IECM installer software. The software is divided into three categories.

Help Files

The following help files are installed by default in the C:\PROGRAM FILES\IECM_CS directory by the installation program:

Iecmint.cnt: IECM "Getting Started" online help contents file.

Iecmint.hlp: IECM "Getting Started" online help file.

Program Files

All applications and their support files specific to the IECM software itself are considered program files. These can be installed into any directory during installation. The folder can be changed from the default location suggested during installation.

GSPROP32.DLL: Graphics Server for Windows 6.15 support file.

GSW32.EXE: Graphics Server for Windows 6.15 program file.

GSWAG32.DLL: Graphics Server for Windows 6.15 support file.

GSWDLL32.DLL: Graphics Server for Windows 6.15 support file.

LTDIS13N.DLL: Graphics Server for Windows 6.15 support file.

LTEFX13N.DLL: Graphics Server for Windows 6.15 support file.

LTFIL13N.DLL: Graphics Server for Windows 6.15 support file.

LTKRN13N.DLL: Graphics Server for Windows 6.15 support file.

- MFC71.DLL: Microsoft Foundation Class .support file for Visual Studio .NET.
- MFC71U.DLL: Microsoft Foundation Class .support file for Visual Studio .NET.

MSVCR71.DLL: Microsoft Visual C runtime library.

- HISTORY.TXT: History of the IECM software, including features installed and planned.
- IECMILIB.DLL: IECM interface support file. It handles all database, uncertainty and model access.
- IECMINT. EXE: IECM program file for the interface.
- IECMINT. MDB: Microsoft Access 97 template database file.
- LHS.DLL: IECM interface support file. It handles all uncertainty sampling.
- LHS_C.DLL: IECM interface support file. It handles all uncertainty sampling.

LICENSE.TXT: IECM license agreement.

- MODEL.DLL: IECM interface model support file. It contains all the technology performance and cost modules.
- SPR32d60.dll: Spread 6.0 support file.
- Tab32d30.dll: Tab Pro 3.1 support file.
- UNWISE32.EXE: Uninstaller program. This requires an installer log created during installation.

Interface Files

The "C:\Program Files\IECM_CS/intdb" directory contains the database files used by the IECM interface. These contain default data used in the interface program. The following files are installed by the installation program:

- Intdesc.mdb: Microsoft Access database file. It contains all the descriptions for the IECM interface screens.
- Model_Default_fules.mdb: Microsoft Access database file. It contains the model default coal information.

Session Database Files

The "C:\Program Files\IECM_CS\sessdb" directory contains the database files created by the IECM interface. All user data associated with sessions are stored here. These files are not created by the installation program; rather, they are created by the IECM Interface at runtime if they are not available. This means that user data cannot be overwritten by the installation program.

System Files

Several files are installed into the windows system directory. These system files are common to many Windows applications. All of these files are created and distributed freely through Microsoft ® Corporation using their installer packages. These system files are unique to the other IECM components listed above because they are hard-wired into the system registry file. In order to maintain consistency with the operating system and stability with the IECM interface, these special system files must be stored in the windows system directory and installed with software installers directly from Microsoft.

A full list of the Microsoft [®] Corporation files installed is provided in the INSTALLR.TXT file located on the IECM compact disk (CD).

Microsoft Data Access Components

The use of Microsoft Access database files requires the installation of ODBC drivers and support files from Microsoft. ODBC is a programming interface that enables applications to access data in database management systems that use Structured Query Language (SQL) as a data access standard. The Microsoft MDAC package is included with the IECM installer program as delivered directly from Microsoft and delivers this important functionality. Files are installed into the "C:\Windows\System32" directory.

Microsoft Visual Basic 4.0 Runtime

The components of this package are installed from within the IECM installer as delivered by Microsoft. They provide Microsoft Visual Basic support files and are

installed into the "C:\Windows\System32" directory and the "C:\Program Files\Common\Microsoft" directory.

Microsoft MFC 4.2

The components of this package are installed from within the IECM installer as delivered by Microsoft. They are Microsoft Visual C++ support files delivered under the Microsoft Foundation Class libraries. They are installed into the "C:\Windows\System32" directory.

Files Modified by Install

Currently no user files are modified when the IECM software is installed. All user files are stored in the "C:\Program Files\IECM_CS\Sessdb" directory.

Configure Plant

Configuring the Combustion Boiler Plant

The following configuration options are available when the **Combustion (Boiler)** is selected as the plant type from the **New Session** pull down menu.

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Configure Plant - Combustion (Boiler) input screen

The figure above shows the base configuration of the PC plant. Combustion, postcombustion, and solids management controls must be configured by the user. The following sections describe each popup menu on the configuration screen.

Pre-configuration settings can be selected using the Configuration menu at the top of the screen. **No Devices** is the default.

### **Combustion Controls**

These configuration options determine the type of furnace and any technologies for reducing  $NO_x$  emissions.

**Fuel Type:** Coal is the primary fuel used by the PC plant. The choices also include the following which are grayed out and may be available in the future:

- Coal
- Oil
- Natural Gas
- Other

**NO_x Control:** From this configuration screen, you may choose.

- None
- In-Furnace Controls: Controls include an assortment of options which combine low NO_x burners (LNB) with overfire air (OFA), selective non-catalytic reduction (SNCR), and natural gas reburn. These options are selected from a pull-down menu in the **Set** <u>Parameters menu</u>

### **Post-Combustion Controls**

These configuration options determine the presence and type of post-combustion emissions controls.

 $NO_x$  Control: The default option is None. The choices available are

- **None**, for no post-combustion NO_x control
- Hot Side SCR for a Hot-Side Selective Catalytic Reduction technology. Although an SCR technology can be positioned at various points along the flue gas train, the IECM considers only the hot-side, high dust configuration. Hot Side SCR may be together with In-Furnace Controls.

Particulates: The default option is None. The None setting is not available when the Mercury technology option is either Carbon
Injection or Carbon + Water Injection. This assures the removal of the carbon being injected immediately downstream of the air preheater.

Multiple fabric filter types are provided. Fabric filter types are based on the bag cleaning techniques used. Various bag-cleaning techniques influence other process parameters. The choice of the bag cleaning method is usually based on the type of coal used—and therefore the filterability of the ash—and your experience with filtering the particular kind of ash. The particular option you select determines the air to cloth ratio, bag life, bag length, power requirements, pressure drop, capital costs and O&M costs.

The choices available are:

- **None:** for no post-combustion particulate control
- Cold Side ESP: for a Cold-Side Electrostatic Precipitator
- **Reverse Gas Fabric Filter:** Uses an off-line bag cleaning technique in which an auxiliary fan forces a relatively gentle flow of filtered flue gas backwards through the bags causing them to partially collapse and dislodge the dust cake. Over 90% of baghouses in U. S. utilities use reverse-gas cleaning.

- **Reverse Gas Sonic Fabric Filter:** Uses a variation of Reverse Gas cleaning in which low frequency pneumatic horns sound simultaneously with the flow of reverse gas to add energy to the dust cake removal process.
- Shake & Deflate Fabric Filter: Uses a method for off-line cleaning in which the bags are mechanically shaken immediately after or while a small quantity of filtered gas is forced back to relax the bags. The amount of filtered gas used is smaller than that used in Reverse Gas cleaning.
- **Pulse-Jet Fabric Filter:** Uses a method for on-line cleaning in which pulses of compressed air are blown down inside and through the bags to remove dust cake while the bags are filtering flue gas. Wire support cages are used to prevent bag collapse during filtration and ash is collected outside of the bags.

**SO₂ Control:** The default option is **None**. The following choices available are:

- **None:** for no post-combustion SO₂ control
- Wet FGD: for a Wet Flue Gas Desulfurization technology. Multiple reagent options are available under the SO₂ Control tab in the Set <u>Parameters</u> section of the interface.
- **Lime Spray Dryer:** for a dry scrubber using lime as a reagent. The interfact places this technology before the particulate control technology in the plant design and diagrams.
- **Mercury:** The default option is **None**. Other options are only available if a particulate control is configured. The options provided are:

None: for no mercury control

- **Carbon Injection:** Although some mercury removal is accomplished naturally in a power plant. It is believed that some mercury is captured or trapped in ash and is removed with bottom ash and fly ash. Carbon injection is provided as a technology to achieve higher removals by injecting fine particles of activated carbon into the flue gas after the air preheater.
- **Carbon + Water Injection:** Because the removal increases with lower flue gas temperatures, water injection is added to the carbon injection as a second technology option.
- **CO₂ Capture:** The default option is **None**. The following choices available are:

**None:** for no CO₂ capture.

- **Amine System:** this option puts an amine scrubber at the end of the flue gas train. Other locations may be available in the future.
- **CO₂ Adsorption:** this option is grayed out and may be available in the future.
- **O₂ Transport Membrane:** this option is grayed out and may be available in the future.
- **Cryogenics:** this option is grayed out and may be available in the future.

### **Solids Management**

- **Flyash Disposal:** This configuration setting determines how flyash is disposed. Fly ash collected from a particulate removal system is typically combined with other solid waste streams if other waste streams exist. The waste disposal option has little effect on the rest of the IECM. The choices are
  - **No Mixing:** for no flyash mixing. This option disposes the flyash separately.
  - Mixed w/FGD Wastes: to dispose flyash with FGD wastes. This option can only be selected if a wet FGD is configured under the SO₂ Control option.
  - **Mixed w/ Bottom Ash:** to dispose flyash with bottom ash (e.g. in the pond).

# **Configuring the Combustion Turbine Plant**

The following configuration options are available when the **Combustion** (**Turbine**) is selected as the plant type from the **New Session** pull down menu.



Configure Plant – Combustion (Turbine) input screen.

The figure above shows the base configuration of the Combustion (Turbine) or NGCC plant. Only post-combustion controls can be configured by the user. The following sections describe each popup menu on the configuration screen.

Pre-configuration settings can be selected using the Configuration menu at the top of the screen. **No Devices** is the default.

### **Post-Combustion Controls**

**CO₂ Capture:** The default is **None**. The following options are available:

- **None:** No CO₂ capture is used.
- **Amine System:** An MEA scrubber is the only method currently available in the IECM for capturing CO₂.
- **CO₂ Adsorption:** This method of CO₂ capture is grayed out in the menu and is planned for a future release of the model.
- **O₂ Transport Membrane:** This method of CO₂ capture is grayed out in the menu and is planned for a future release of the model.
- **Cryogenics:** This method of CO₂ capture is grayed out in the menu and is planned for a future release of the model.

# **Configuring the IGCC**

The following configuration options are available when the **IGCC** is selected as the plant type from the **New Session** pull down menu.

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		Solids Management Slag Landfill Sulfur Sulfur Plant		

Configure Plant – IGCC input screen.

The figure above shows the base configuration of the IGCC plant. Gasification, postcombustion, and solids management controls can be configured by the user. The following sections describe each popup menu on the configuration screen.

Pre-configuration settings can be selected using the Configuration menu at the top of the screen. **Base GE Quench** is the default.

### **Gasification Options**

**Gasifier:** There is a pull down menu so that the user may select the gasifier type. The choices are:

• **GE (Oxygen blown):** This is the only gasifier currently available in the model.
- **E-Gas (Oxygen blown):** This option is grayed out in the pull down menu and will be available in a future release of the model.
- **KRW (Air blown):** This option is grayed out in the pull down menu and will be available in a future release of the model.
- **Shell (Oxygen blown):** This option is grayed out in the pull down menu and will be available in a future release of the model.

**Gas Cleanup:** This menu will be used in the future to allow a user to select a suite of gas cleanup technologies. Particular devices for removing solids and sulfur while altering the syngas temperature are loaded with this menu. Presently, Cold-gas Cleanup is used with the GE (Oxygen-blown) gasifier in the model. The future choices will be:

- **None:** This option is grayed out in the pull down menu and will be available in a future release of the model.
- **Warm-gas:** This option is grayed out in the pull down menu and will be available in a future release of the model.
- **Cold-gas:** This is implemented in the model.

 $CO_2$  Capture: The default is **None**. The user may select from the  $CO_2$  Capture pull down menu whether or not to capture  $CO_2$  and the method of capture.

- **None:** no CO₂ capture is used.
- **Sour Shift + Selexol:** This option is the only one currently available in the model.
- **Sweet Shift + Selexol:** This option is grayed out in the pull down menu and will be available in a future release of the model.
- **Shift + Comb. CO₂/H₂S:** This option is grayed out in the pull down menu and will be available in a future release of the model.

#### **Post-Combustion Controls**

**NO_x Control:** At present the only option available for selection is **None**. The following are provided in the menu:

- **None:** No NO_x control is used.
- **SCR:** This option is grayed out and will be available in a future release of the model.

#### **Solids Management**

**Slag:** Landfill is the default. The following choices are available:

- **None:** Slag collected is not sent to a landfill.
- Landfill: The slag collected is disposed in a landfill.

**Sulfur:** Sulfur captured can be processed by the following equipment options:

• **Sulfur Plant:** Sulfur is processed into a solid form. This option is the only one currently available in the model.

• **Sulfuric Acid Plant:** Sulfur is processed into an acid form. This option is grayed out in the pull down menu and may be available in a future release of the model.

# **Combustion Overall Plant**

The input parameter screens described in the following sections are available when the **Combustion (Boiler)** is selected as the plant type from the **New Session** pull down menu. These screens apply to the power plant as a whole, not to specific technologies.

### **Combustion Overall Plant Diagram**

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Combustion Overall Plant – Diagram result screen.

This **Diagram** appears in the <u>Configure Plant</u>, Set <u>Parameters</u> and <u>Get</u> **Results** program areas. The screen displays the plant configuration settings on the left side of the page and a diagram of the configured plant on the right of the page. No input parameters or results are displayed on this screen.

### **Combustion Overall Plant Performance Inputs**

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Combustion Overall Plant—Performance input screen.

The parameters available on this screen establish the plant availability, electrical requirements, and ambient conditions for the power plant. These parameters have a major impact on the performance and costs of each of the individual technologies.

- **Capacity Factor:** This is an annual average value, representing the percent of equivalent full load operation during a year. The capacity factor is used to calculate annual average emissions and materials flows.
- **Gross Electrical Output:** This is the gross output of the generator(s) in megawatts (MWg). The value does not include auxiliary power requirements. The model uses this information to calculate key mass flow rates. The value here is shown for reference only. The value can be changed for a combustion plant by navigating to the <u>Base Plant</u> <u>Performance Inputs</u> (page 95) screen.
- **Net Electrical Output:** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties). The value cannot be changed and is shown for reference only.
- **Ambient Air Temperature:** This is the inlet temperature of the ambient combustion air prior to entering the preheater. The model presumes an *annual average* temperature. Inlet air temperature affects the boiler energy balance and efficiency. It provides a reference point for the calculation of pressure throughout the system. Currently, the model cannot have temperatures below 77°F.
- **Ambient Air Pressure:** This is the absolute pressure of the air inlet stream to the boiler. The air pressure is used to convert flue gas molar flow rates to volume flow rates.

**Ambient Air Humidity:** This is the water content of the inlet combustion air. This value is used in calculating the total water vapor content of the flue gas stream. The value is referred to as the specific humidity ratio, expressed as a ratio of the water mass to the dry air mass.

# **Combustion Overall Plant Constraints Inputs**

The **Constraints** input parameters define the emission constraints as they apply to the gases emitted from the power plant.

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6			Configure Plant	Set Par	amet	ers			<u>G</u> et Res	ults	
		Ove <u>r</u> all Plant	Fuel Base Plant Merc	cury <u>N</u> Ox Control	<u>T</u> Cor	SP <u>S</u> o ntrol Cor	D2 ntrol	C <u>O</u> 2 Capture	By-Pr Mgr	od. nt Sta	ıc <u>k</u>
8			Title	Units	Unc	Value	Calc	Min	Max	Default	
X		1	Sulfur Dioxide Emission Constraint	1b/MBtu		0.6000	V	0.0	15.00	calc	
8		2	Nitrogen Oxide Emission Constrain	t 1b/MBtu		0.1500	Ľ	0.0	5.000	calc	
		3	Particulate Emission Constraint	1b/MBtu		3.000e-02	Ľ	0.0	1.000	calc	
		4	Total Mercury Removal Efficiency	%		70.00		0.0	99.00	70.00	
		5	Total CO2 Removal Efficiency	%		90.00		0.0	99.00	90.00	
		6									
		7									
		8									
		9									
<u>.</u>		1	J								
		1									
		14									
		1.									
		14	5								
		10	5								
		13	7								
		18	8								
		Pro	cess Type: Overall Plant								
		1.1	Diagram 🖌 2. Performance 🗼	<u>3</u> . Constraints	<u>4</u> .	Financing	K.	5. O&M Co:	st 🖌 🤅	<u>i</u> . Emis. Taxe:	5

Overall Plant – Emission Constraints input screen.

This screen accepts input for the allowable emission limits for sulfur dioxide, nitrogen oxides and particulate matter. Mercury and carbon dioxide are constrained by their removal efficiencies across the entire plant.

The default values for the calculated inputs reflect current United States New Source Performance Standards (NSPS), which are applicable to all units constructed since 1978.  $SO_2$  emission limits are based on the NSPS limits that are a function of the sulfur content of the coal.

The emission constraints determine the removal efficiencies of control systems for  $SO_2$ ,  $NO_x$ , and particulate matter required to comply with the specified emission constraints. As discussed later, however, user-specified values for control technology performance may cause the plant to over-comply or under-comply with the emission constraints specified in this screen. Each parameter is described briefly below.

**Sulfur Dioxide Emission Constraint:** The emission constraint is defined by the 1979 revised NSPS. The calculated value is determined by the potential emission of the raw coal, minus the amount of sulfur retained in the ash streams. The emission limit is dependent on the fuel type and is used to determine the removal efficiency of  $SO_x$  control systems.

**Nitrogen Oxide Emission Constraint:** The combined emissions of NO₂ and NO₃ of present power plants are constrained by NSPS

standards. The limit is a function of the coal rank and fuel type and is used to determine the removal efficiency of  $NO_x$  control systems.

- **Particulate Emission Constraint:** The emission constraint of the total suspended particulates is defined by the NSPS standards of 1978. The limit is a function of the fuel type and is used to determine the removal efficiency of particulate control systems.
- **Total Mercury Removal Constraint:** The emission constraint of total after the economizer. Mercury removed in the furnace due to bottom ash removal is not considered in this constraint. The limit determines the removal efficiency of the particulate control systems.
- **Total CO₂ Removal Constraint:** The emission constraint applies to all the air emission sources in the power plant, primary or secondary. The default value is based on recent discussions and is not based on any currently enforced law.

### **Combustion Overall Plant Financing Inputs**

Inputs for the financing costs of the base plant itself are entered on the **Financing** input screen.

	<u>C</u> onfigure Plant	Set <u>P</u> ara	umet	ers			<u>G</u> et Res	sults
Ove <u>r</u> all Plant	Fuel Base Plant Mer	cury <u>N</u> Ox Control	<u>T</u> Cot	SP <u>S</u> O ntrol Cor	D2 ntro1	C <u>O</u> 2 Capture	By-Pı Mg	rod. S mt S
	Title	Units	Unc	Value	Calc	Min	Max	Default
1	Year Costs Reported			2003 💌		Menu	Menu	2003
2	Constant or Current Dollars?			Constant		Menu	Menu	Constant
3	Discount Rate (Before Taxes)	fraction		0.1030	M	0.0	2.000	calc
4	Fixed Charge Factor (FCF)	fraction		0.1480	M	0.0	1.000	calc
5	Or, specify all the following:							
6	Inflation Rate	%/yr		0.0	M	0.0	20.00	calc
7	Plant or Project Book Life	years		30.00		5.000	60.00	30.00
8	Real Bond Interest Rate	%		9.000		0.0	15.00	9.000
9	Real Preferred Stock Return	%		8.500		0.0	20.00	8.500
10	Real Common Stock Return	%		12.00		0.0	25.00	12.00
11	Percent Debt	%		45.00		0.0	100.0	45.00
12	Percent Equity (Preferred Stock)	%		10.00		0.0	100.0	10.00
13	Percent Equity (Common Stock)	%		45.00	M	0.0	100.0	calc
14								
15	Federal Tax Rate	%		35.00		15.00	50.00	35.00
16	State Tax Rate	%		4.000		0.0	10.00	4.000
17	Property Tax Rate	%		2.000		0.0	5.000	2.000
18	Investment Tax Credit	%		0.0		0.0	20.00	0.0

Overall Plant—Financing input screen.

This screen describes the factors required to determine the carrying charge for all capital investments. The carrying charge is defined as the revenue required for the capital investment. The total charge can also be expressed as a levelized cost factor or fixed charge factor. The fixed charge factor is a function of many items. The fixed charge factor can be specified directly or calculated from the other input quantities below it on the financial input screen.

Each parameter is described briefly below.

Year Costs Reported: This is the year in which all costs are given or displayed, both in the input screens and the results. A cost index is used

by the IECM to scale all costs to the cost year specified by this parameter. The cost year is reported on every input and result screen associated with costs throughout the interface.

- **Constant or Current Dollars:** Constant dollar analysis does not include the affect of inflation, although real escalation is included. Current dollar analysis includes inflation and real escalation. This choice allows you to choose the mode of analysis for the entire IECM economics. The cost basis is reported on every input and result screen associated with costs throughout the interface.
- **Discount Rate (Before Taxes):** This is also known as the cost of money. Discount rate (before taxes) is equal to the sum of return on debt plus return on equity, and is the time value of money used in before-tax present worth arithmetic (i.e., levelization).
- **Fixed Charge Factor (FCF):** The fixed charge factor is one of the most important parameters in the IECM. It determines the revenue required to finance the power plant based on the capital expenditures. Put another way, it is a levelized factor which accounts for the revenue per dollar of total plant cost that must be collected from customers in order to pay the carrying charges on that capital investment.

One may specify a fixed charge factor, or fill in the following inputs and the model will calculate the FCF based on them:

- **Inflation Rate:** This is the rise in price levels caused by an increase in the available currency and credit without a proportionate increase in available goods or services. It does not include real escalation.
- **Plant or Project Book Life:** This is the years of service expected from a capital investment. It is also the period over which an investment is recovered through book depreciation.
- **Real Bond Interest Rate:** This is a debt security associated with a loan or mortgage. It is the most secure form of security but the lowest in its return.
- **Real Preferred Stock Return:** This equity security is the second most speculative type and pays the second highest rate of return. The holder of the stock is a part owner of the company.
- **Real Common Stock Return:** This is the most speculative type of equity security sold by a utility and pays the highest relative return. The holder of the stock is a part owner of the company.
- **Percent Debt:** This is the percent of the total capitalization that is associated with debt money. This includes loans and mortgage bonds.
- **Percent Equity (Preferred Stock):** This is the percent of the total capitalization that is associated with the sale of preferred stock.
- **Percent Equity (Common Stock):** This value is the remainder of the capitalization, calculated as 100% minus the percent debt, minus the percent equity in preferred stock.
- Federal Tax Rate: This is the federal tax rate. It is used to calculate the amount of taxes paid and deferred.
- **State Tax Rate:** This is the state tax rate. It is used to calculate the amount of taxes paid and deferred.

- **Property Tax Rate:** The property tax rate, or ad valorem, is used to calculate the carrying charge.
- **Investment Tax Credit:** This is an immediate reduction in income taxes equal to a percentage of the installed cost of a new capital investment. It is zero by default. It is used to set the initial balance and the book depreciation.

### **Combustion Overall Plant O&M Inputs**

This screen combines the variable O&M unit costs from all the model components and places them in one spot. These values will also appear in the technology input screens where they are actually used. Values changed on this screen will reflect exactly the same change everywhere else they appear. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

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	<u>(</u>	<u>C</u> onfigure Pla	nt		Set <u>P</u> ar	amet	ers			Get Res	alts	
	Ove <u>r</u> all Plant	Fuel B	lase Plant 🛛 🔟	ercury	<u>N</u> Ox Control	<u>T</u> : Cor	SP SP atrol Co	O2 ntro1	C <u>O</u> 2 Captur	By-Pro Mgn	ud. Sta	ıc <u>k</u>
		Ti	itle		Units	Unc	Value	Calc	Min	Max	Default	
Ш	1	Internal COE for (	Comp. Allocatio	ns			Base Pla ▼		Menu	Menu	se Plant (u	
Ш	2	Internal Electricity	y Price		\$/MWh		41.12		0.0	200.0	calc	
Ш	3											
Ш	4	As-Delivered Co	al Cost		\$/ton		27.70		0.0	100.0	calc	
Ш	5	Natural Gas Cost			\$/mscf		5.346		0.0	10.00	calc	
Ш	6	WaterCost			\$/1000 gal		0.8316		0.0	2.500	calc	
Ш	7											
Ш	8	Limestone Cost			\$/ton		19.64		0.0	30.00	calc	
Ш	9	Lime Cost			\$/ton		72.01		40.00	90.00	calc	
Ш	10	Ammonia Cost			\$/ton		248.2		100.0	400.0	calc	
Ш	11	UreaCost			\$/ton		412.4		200.0	400.0	calc	
Ш	12	MEA Cost			\$/ton		1293		0.0	1.500e+04	calc	
Ш	13	Activated Carbor	n Cost		\$/ton		1322		500.0	5000	calc	
Ш	14	Caustic (NaOH) (	Cost	_	\$/ton		624.7		0.0	2000	calc	
Ш	15											
Ш	16	Operating Labor I	Rate		\$/hr		24.82		0.0	100.0	24.82	
Ш	17											
Ш	18											
ш	Proc	ess Type: Ovo	rall Plant		-		Costs are	in Con	stant 2005	5 dollars.		

Overall Plant – O&M Cost input screen.

**Internal COE for Comp. Allocations:** This is a pop-up selection menu that determines the method for determining electricity costs within the power plant. The selection of this pop-up menu determines the actual internal electricity price on the next line. The options are:

- Base Plant (uncontrolled)
- User Specified
- Total Plant COE

Internal Electricity Price: This is the price of electricity and is calculated as a function of the utility cost of the base plant. The base plant for the **Combustion (Boiler)** model is assumed to be a coal pile, combustion boiler, air preheater, and disposal sites. This value is calculated and provided for reference purposes only unless **User Specified** is selected in the pop-up in the previous line. As-Delivered Coal Cost: This is the cost of the coal as-delivered.

- **Natural Gas Cost:** This is the cost of natural gas in dollars per thousand standard cubic feet.
- Water Cost: This is the cost of water in dollars per thousand gallons.
- **Limestone Cost:** This is the cost of limestone in dollars per ton.
- Lime Cost: This is the cost of lime in dollars per ton.
- Ammonia Cost: This is the cost of ammonia in dollars per ton.
- Urea Cost: This is the cost of natural gas in dollars per ton.
- **MEA Cost:** This is the cost of MEA in dollars per ton.
- Activated Carbon Cost: This is the cost of activated carbon in dollars per ton.
- **Caustic (NaOH) Cost:** This is the cost of caustic (NaOH) gas in dollars per ton.
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

# **Combustion Overall Plant Emis. Taxes Inputs**

This screen allows users to specify emission taxes or credits as part of the overall plant cost economics. Taxes or credits are typically provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

<b>V IE</b> File	CM <u>E</u> d	<b>i Interface</b> it <u>V</u> iew G	io <u>W</u> indow <u>F</u>	<u>t</u> elp										
пI	<b>.</b> F •	Untitled*												<u>- I X</u>
6		<u>(</u>	<u>C</u> onfigure I	Plant	Ì	S	et <u>P</u> ara	amete	rs	Ĩ		<u>G</u> et Res	sults	
	ľ	Ove <u>r</u> all Plant	F <u>u</u> el	<u>B</u> ase Plant	<u>M</u> ercu	na [	<u>4</u> Ox ontrol	<u>T</u> S Con	tro1 (	<u>S</u> O2 Control	C <u>O</u> 2 Capture	By-Pi Mg	nd. Si	ac <u>k</u>
9				Title		Un	its	Unc	Value	Calc	Min	Max	Default	
Х.	III	1	Tax	on Emissions										
1	Ш	2	Sulfur Dioxide	e (SO2)		\$/t	on		0.0		0.0	5000	0.0	
2	Ш	3	Nitrogen Oxid	le (equiv. NO2)		\$/t	on		0.0		0.0	5000	0.0	
	Ш	4	Carbon Dioxi	de (CO2)		\$/t	on		0.0		0.0	5000	0.0	
	Ш	5												
	Ш	0												
	Ш	7												
<u> </u>	Ш	0								_				
2	Ш	10												
-	Ш	11												
	Ш	12												
	Ш	13												
		14												
	Ш	15												
	Ш	16												
	Ш	17												
	Ш	18												
		Proc	ess Type:	verall Plant			Y		Costs a	re in Cor	ıstant 2005	dollars.		
		<u>1</u> . Di	agram /	2. Performanc	e /	<u>3</u> . Constra	aints /	4	Financing		<u>5</u> . O&M Co:	st 🔪 🤉	<u>6</u> . Emis. Tax	s

Emission Constraint Emission Taxes input screen.

The **Emis. Taxes** input screen allows the user to enter the taxes on emissions in dollars per ton. The final costs determined from these inputs are available under the stack tab in the results section of the IECM. The costs are added to the overall plant cost, not a particular technology.

#### **Tax on Emissions**

- Sulfur Dioxide (SO₂): The user may enter a cost to the plant of emitting sulfur dioxide in dollars per ton.
- Nitrogen Oxide (equiv. NO_x) : The user may enter a cost to the plant of emitting nitrogen oxide in dollars per ton.
- **Carbon Dioxide (CO₂):** The user may enter a cost to the plant of emitting carbon dioxide in dollars per ton.

## **Combustion Overall Plant Performance Results**

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Eile <u>B</u>	di	t <u>⊻</u>	<u>/</u> ie	w Go <u>W</u> indow <u>H</u> elp				
ъđ	F	Un	til	led [*]				
6				<u>C</u> onfigure Plant	Set Pa	rame	ters <u>G</u> et Res	ults
	ſ	Ov P1	'e <u>r</u> lar	all t Fuel <u>B</u> oiler <u>A</u> ir Preheater	NOx Control Me	rcury	<u>TSP</u> <u>S</u> O2 <u>CO</u> 2 <u>By</u> Control Control Capture M	Prod. gmt Stac <u>k</u>
<b>3</b>				Performance Parameter	Value		Plant Energy Requirements	Value
1		1		Net Electrical Output (MW)	331.8	1	Gross Electrical Output (MWg)	500.0
91 I		2	2			2	Aux. Power Produced (MW)	0.0
		3	1	Primary Fuel Power Input (MBtu/hr)	4419	3		
		4	ŀ.	Aux. Fuel Power Input (MBtu/hr)	0.0	4	Boiler Use (MW)	29.25
2		5	;	Total Plant Power Input (MBtu/hr)	4419	5		
2111		6	5			6	Hot-Side SCR Use (MW)	2.721
7		7	'	Gross Plant Heat Rate, HHV (Btu/kWh)	8838	7	Cold-Side ESP Use (MW)	0.9125
-11		8	3	Net Plant Heat Rate, HHV (Btu/kWh)	1.332e+04	8	Wet FGD Use (MW)	14.02
		9				9	Activated Carbon Inj. Use (MW)	5.839e-02
		10	0	Annual Operating Hours (hours)	6575	10	Amine Scrubber Use (MW)	121.2
		11	1	Annual Power Generation (BkWh/yr)	2.181	11		
		12	2			12	CO2 Sequestration Use (MW)	0.0
		13	3	Net Plant Efficiency, HHV (%)	25.62	13	Net Electrical Output (MW)	331.8
		14	4			14		
		15	5			15		
		P	ro	cess Type: Overall Plant	<b>V</b>			
	ľ		1	Diagram <u>2</u> , Plant Perf. <u>3</u> , Mass I	n/Out 🔏 4. Solid	is In/C	ut 🖉 <u>5</u> . Gas In/Out 🖌 <u>6</u> . Total Cost 🖌	7. Cost Summary

Combustion Overall Plant – Plant Perf. result screen.

The **Plant Perf.** result screen displays performance results for the plant as a whole. Heat rates and power in and out of the power plant are given. Each result is described briefly below.

#### **Performance Parameter**

- **Net Electrical Output:** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).
- **Primary Fuel Power Input:** This is the fuel energy input for the plant, given on an hourly basis (maximum capacity). This rate is also referred to as the fuel power input.
- **Aux. Fuel Power Input:** This is the fuel energy input for the auxiliary natural gas boiler if used with the Amine System. This is additional fuel energy used by the plant, given on an hourly basis. This rate is also referred to as the auxiliary fuel power input.

- **Total Plant Power Input:** This is the total of all the fuel energy used by the plant, given on an hourly basis (maximum capacity). This rate is also referred to as the total plant power input.
- **Gross Plant Heat Rate:** This is the heat rate of the gross cycle including the effects of the boiler efficiency. This is considered the gross heat rate.
- **Net Plant Heat Rate:** This is the net heat rate, which includes the effect of plant equipment and pollution control equipment.
- **Annual Operating Hours:** This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.
- **Annual Power Generation:** This is the net annual power production of the plant. The capacity factor and all energy credits or penalties are used in determining its value.
- **Net Plant Efficiency:** The net plant efficiency is displayed here on a HHV basis.

#### **Plant Power Requirements**

A second group of results provide a breakdown of the internal power consumption for the individual technology areas. These are all given in units of megawatts. Individual plant sub-components will only be displayed when they are configured in the **Configure Plant** section of the model.

- **Gross Electrical Output:** This is the gross output of the generator in megawatts (MWg). The value does not include auxiliary power requirements. The model uses this information to calculate key mass flow rates. The value is an input parameter.
- **Aux. Power Produced:** If an auxiliary natural gas boiler is used to provide steam and power for the Amine System, this is the additional electricity that it produces.
- **Component Electrical Uses:** Power used by various plant and pollution control equipment is reported in the middle portion of the second column. The number displayed varies as a function of the components configured in the power plant.
- **Net Electrical Output:** This is the net plant capacity, which is the gross plant capacity plus any auxiliary electrical output minus the losses due to plant equipment and pollution equipment (energy penalties). This is the same value used in the first column.

### **Combustion Overall Plant Mass In/Out**

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<u>F</u> ile	<u>E</u> di	t <u>V</u> ie	w Go <u>W</u> indow <u>H</u> elp				
ъI	<b>.F</b> -	Unti	tled*				
6	Γ		Configure Plant	Set <u>P</u> ai	ame	ters <u>G</u> et Res	ults
	ľ	Over Plar	all F <u>u</u> el <u>B</u> oiler <u>A</u> ir ht Preheater	NOx Control Me	cury	ISP <u>S</u> O2 C <u>O</u> 2 <b>By</b> - Control Control Capture M	Prod. gmt Stac <u>k</u>
*			Chemical Inputs	Flow Rate (tons/hr)		Solid & Liquid Outputs	Flow Rate (tons/hr)
ß		1	Coal	166.6	1	Bottom Ash Disposed	2.431
<u>م</u>		2	Oil	0.0	2	Fly Ash Disposed	0.0
		3	Natural Gas	0.0	3	Scrubber Solids Disposed	0.0
		4	Total Fuels	166.6	4	Particulate Emissions to Air	9.722
		5			5	Captured CO2	0.0
21		6	Lime/Limestone	0.0	6	Byproduct Ash Sold	0.0
2		7	Sorbent	0.0	7	Byproduct Gypsum Sold	0.0
<u>~</u>		8	Ammonia	0.0	8	Byproduct Sulfur Sold	0.0
		9	Urea	0.0	9	Byproduct Sulfuric Acid Sold	0.0
		10	Dibasic Acid	0.0	10	Total	12.15
		11	Activated Carbon	0.0	11		
		12	Total Chemicals	0.0	12	See Tab	
		13			13		
		14			14		
		15			15		
		Pro	cess Type: Overall Plant	T			
			. Diagram 🖌 <u>2</u> . Plant Perf. <u>3</u> . Mass I	n/Out / <u>4</u> . Solid	ls In/C	ut / 5. Gas In/Out / 6. Total Cost /	7. Cost Summary

Combustion Overall Plant – Mass In/Out result screen.

The **Mass In/Out** result screen displays the flow rates of fuels and chemicals into the plant and solid and liquid flow rates out of the plant. Each result is described briefly below.

#### **Input Flow Rates**

**Coal:** Total mass of coal entering the boiler on a wet basis.

Oil: Total mass of oil used in the power plant

- Natural Gas: Total mass of natural gas used in the power plant
- **Total Fuels:** This is the total fuel mass entering the power plant. This result is highlighted in yellow.
- Lime/Limestone: Total mass of this reagent used in the power plant on a wet basis.
- **Sorbent:** This is the total mass of sorbent used in the power plant. The sorbent currently used is an amino acid used in the  $CO_2$  capture device.
- Ammonia: Total mass of ammonia used in the power plant.
- **Urea:** Total mass of urea used in the power plant. Urea is the reagent used to reduce NO_x in the SNCR technology.
- Dibasic Acid: Total mass of dibasic acid used in the power plant.
- Activated Carbon: Total mass of activated carbon injected in the power plant.
- **Total Chemicals:** This is the total reagent mass entering the power plant. This result is highlighted in yellow.

#### **Output Flow Rates**

- **Bottom Ash Disposed:** Total mass of bottom ash collected in the power plant on a dry basis.
- Fly Ash Disposed: Total mass of fly ash collected in the power plant on a dry basis.
- **Scrubber Solids Disposed:** Total mass of scrubber solid wastes collected in the power plant on a dry basis.
- **Particulate Emissions to Air:** Solids that remain in the flue gas and exit the plant are reported on a mass basis.
- **Captured CO₂:** If a CO₂ capture technology has been selected, the mass flow of CO₂ captured is reported. It is transported off site. See the <u>CO₂</u> <u>Transport System</u> (page 355) for more information.
- **Byproduct Ash Sold:** Total mass of ash (bottom and fly ash) sold in commerce as a by-product on a dry basis.
- **Byproduct Gypsum Sold:** Total mass of flue gas treatment solids sold in commerce as a by-product on a dry basis.
- **Byproduct Sulfur Sold:** Total mass of elemental sulfur recovered from flue gas and sold in commerce as a by-product on a dry basis.
- **Byproduct Sulfuric Acid Sold:** Total mass of sulfuric acid recovered from the flue gas and sold in commerce as a by-product.
- **Total:** This is the total wet solid mass exiting the power plant. This result is highlighted in yellow.

#### **Combustion Overall Plant Solids Emissions**

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	Unt	itle	i*					×
			Configure Plant	Set <u>P</u> ara	meters	Ĩ	<u>G</u> et Re	sults
	Ove Pla	rall nt	Fuel <u>B</u> oiler <u>A</u> ir <u>I</u> Preheater Co	NOx ontrol Mercu	ary <u>T</u> SP Control	<u>S</u> O2 Control	CO2 B3 Capture B	r-Prod. Agmt Stac <u>k</u>
			Solid Components (at technology exit unless noted)	Bottom Ash (tons/hr)	Combustion Zone (tons/hr)	Post-Comb. Zone (tons/hr)	Economizer (tons/hr)	SCR (tons/hr)
	Ī	1	Ash	2.413			9.651	
		2	Lime (CaO)	0.0			0.0	
		3	Limestone (CaCO3)	0.0			0.0	
		4	Calcium Sulfite (CaSO3-0.5H2O)	0.0			0.0	
		5	Gypsum (CaSO4-2H2O)	0.0			0.0	
		6	Calcium Sulfate (CaSO4)	0.0			0.0	
		7	Calcium Chloride (CaCl2)	0.0			0.0	
		8	Miscellaneous (UBC, Sulfur)	1.775e-02			7.098e-02	
		9	Water	0.0			0.0	
		10	Total	2.431			9.722	
		11						
		12						
	-	13						
		14						
	Pr	15 •   oce:	ss Type: Overall Plant		 			Þ
		L. D	iagram 🖌 2. Plant Perf. 📈 <u>3</u> . Mass In/0	Dut <u>4</u> . Solids	In/Out <u>5</u> . Ge	as In/Out 🖌 🧃	<u>6</u> . Total Cost 🏼 🦯	( <u>7</u> . Cost Summary/

Combustion Overall Plant – Solids Emissions result screen.

The **Solids In/Out** result screen displays the values for the flow of the solid components in the gas and condensed streams throughout the various stages of the power plant. Each result is described briefly below. Note that each column

represents the flow rate at the exit of the technology specified at the top of the column. Note that the solids are not reported in this detail inside the technology result screens.

#### **Solid Components**

Ash: Total mass of ash (primarily solid oxides).

- Lime (CaO): Total mass flow of lime. This is typically added as a reagent and will react with the flue gas to form another compound.
- **Limestone (CaCO₃):** Total mass flow of limestone. This is typically added as a reagent and will react with the flue gas to form another compound.
- **Calcium Sulfite (CaSO₃-¹/₂H₂O):** Total mass flow of calcium sulfite, a byproduct of lime or limestone reacting with sulfur in the flue gas.
- **Gypsum (CaSO₄-2H₂O):** Total mass flow of gypsum, a byproduct of lime or limestone reacting with sulfur in the flue gas.
- **Calcium Sulfate (CaSO₄):** Total mass flow of calcium sulfate, a byproduct of lime or limestone reacting with sulfur in the flue gas.
- **Calcium Chloride (CaCl₂):** Total mass flow of calcium sulfate, a byproduct of lime or limestone reacting with chlorine or chlorine compounds in the flue gas.
- **Miscellaneous (UCB, Sulfur):** Total mass flow of other solids in the flue gas. This includes unburned carbon or unburned sulfur from the boiler.
- Water: Total mass flow of condensed water associated with the solids stream. This is more clearly represented in what is considered liquid streams. See the **Gas In/Out** screen for a summary of the evaporated water flow rate through the power plant.

#### **Combustion Overall Plant Gas Emissions**

	🗧 Unti	tlec	Configure Plant	Set Poro	meterc	Ĭ	Gat De	
lr	Ove; Plai	rail nt	Fuel Boiler Air Co	IOx ntrol	ry <u>T</u> SP Control	<u>S</u> O2 Control	CO2 B3 Capture P	z-Prod. Mgmt Stac <u>k</u>
			Gas Components (at technology exit unless noted)	APH Oxidant In (Ib-moles/hr)	APH Recycle In (Ib-moles/hr)	APH Heated Air (lb-moles/hr)	Combustion Zone (Ib-moles/hr)	Post-Comb. Zone (Ib-moles/hr)
Ш		1	Nitrogen (N2)	1.081e+05	0.0	1.081e+05		
Ш		2	Oxygen (O2)	2.900e+04	0.0	2.900e+04		
		3	Water Vapor (H2O)	3988	0.0	3988		
		4	Carbon Dioxide (CO2)	0.0	0.0	0.0		
I		5	Carbon Monoxide (CO)	0.0	0.0	0.0		
		6	Hydrochloric Acid (HCl)	0.0	0.0	0.0		
I		7	Sulfur Dioxide (SO2)	0.0	0.0	0.0		
I		8	Sulfuric Acid (equivalent SO3)	0.0	0.0	0.0		
I		9	Nitric Oxide (NO)	0.0	0.0	0.0		
	1	10	Nitrogen Dioxide (NO2)	0.0	0.0	0.0		
	1	11	Ammonia (NH3)	0.0	0.0	0.0		
I	1	12	Argon (Ar)	1292	0.0	1292		
	1	13	Total	1.424e+05	0.0	1.424e+05		
I	1	14						
I	1	15						
								-

Combustion Overall Plant – Gas Emissions result screen.

The **Gas In/Out** result screen displays the values for the flow of the gas components in the flue gas throughout the various stages of the power plant. Each result is described briefly below. Note that each column represents the flow rate at the exit of the technology specified at the top of the column. These are also reported elsewhere in the particular technology result screens but duplicated here to provide a broad look at gas emissions.

#### **Stack Gas Components**

Nitrogen (N₂): Total mass of emitted nitrogen.

**Oxygen (O₂):** Total mass of emitted oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_x): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

**Argon (Ar):** Argon is present in small quantities in atmospheric air. The argon emitted from the power plant is shown on a mass basis.

**Total Gases:** Total flow rate of all gases. This result is highlighted in yellow.

# **Combustion Overall Total Cost**

	Un	titled						
			l*					
. III r			Configure Plant	Set <u>P</u> ara	meters	Ĩ	<u>G</u> et Re	sults
	Ov Pl	erall ant	Fuel Boiler Air A	IOx entrol Mercu	uy <u>T</u> SP Control	<u>S</u> O2 Control	CO2 B3 Capture B	r-Prod. Agmt Stac <u>k</u>
			Technology	Fixed O&M (M\$/yr)	Variable O&M (M\$/yr)	Total O&M (M\$/yr)	Annualized Capital (M\$/yr)	Total Levelized Annual Cost (M\$/yr)
3		1	Combustion NOx Control	0.0	0.0	0.0	0.0	0.0
<b>P</b> 11		2	Post-Combustion NOx Control	0.0	0.0	0.0	0.0	0.0
		3	Mercury Control	0.0	0.0	0.0	0.0	0.0
		4	TSP Control	0.0	0.0	0.0	0.0	0.0
		5	SO2 Control	0.0	0.0	0.0	0.0	0.0
2111		6	Combined SOx/NOx Control	0.0	0.0	0.0	0.0	0.0
2		7	CO2 Capture	0.0	0.0	0.0	0.0	0.0
-11		8	Subtotal	0.0	0.0	0.0	0.0	0.0
		9	Base Plant	13.16	32.21	45.37	67.95	113.3
		10	Emission Taxes	0.0	0.0	0.0	0.0	0.0
		11	Total	13.16	32.21	45.37	67.95	113.3
		12						
		13						
		14						
	P1	15 roce:	ss Type: Overall Plant	Dut / 4 Solids	Costs a	ure in Constant	2003 dollars. i. Total Cost	7. Cost Summary

Combustion Overall Plant Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs associated with the power plant as a whole. The costs summarized on this screen are expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each technology (row) is described briefly below.

**Combustion NO_x Control:** The total cost of the In-Furnace NO_x controls used.

- **Post-Combustion NO**_x **Control:** The total cost of all the Post-Combustion NO_x removal modules used.
- Mercury Control: The total cost of all the mercury control modules used.
- **TSP Control:** The total cost of all the conventional particulate removal modules used.
- **SO₂ Control:** The total cost of all the SO₂ conventional removal modules used.
- **Combined SO_x/NO_x:** The total cost of all the combined  $SO_x/NO_x$  advanced removal modules used.
- **Subtotal:** This is the cost of the conventional and advanced abatement technology modules alone. This is the total abatement cost. The subtotal is highlighted in yellow.
- **Base Plant:** The total cost of the base plant without consideration of any abatement technologies. This can be used to compare with other power plant types.
- **Emission Taxes:** The total cost of taxes assessed to stack emissions is provided here.

**Total:** This is the total cost of the entire power plant. This result is highlighted in yellow.

Each cost category (column) is described briefly below.

- **Fixed O&M:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs for each technology.
- **Variable O&M:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs associated with a technology.
- **Total O&M:** This is the sum of the annual fixed and variable operating and maintenance costs for each technology.
- **Annualized Capital:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow

#### **Combustion Overall Plant Cost Summary**

	<u>(</u>	Con	figure	e Plant	T	Set	t <u>P</u> arameter	rs	<u> </u>	Get Results	
	Ove <u>r</u> ail Plant	F	' <u>u</u> el	<u>B</u> oiler	<u>A</u> ir Preheater	<u>N</u> Ox Control	Mercury	<u>T</u> SP S Control Co	02 C <u>O</u> 2 ntrol Captu	re By-Prod. Mgmt	Stac <u>k</u>
				Te	chnology		Capital Required (M\$)	Capital Required (\$/kW-net)	Revenue Required (M\$/yr)	Revenue Required (\$/MWh)	
l		1	Comb	ustion NOx	Control		0.0	0.0	0.0	0.0	
I		2	Post-C	Combustion	NOx Control		0.0	0.0	0.0	0.0	
		3	Mercu	ary Control			0.0	0.0	0.0	0.0	
		4	TSP C	ontrol			0.0	0.0	0.0	0.0	
l		5	SO2 C	ontrol			0.0	0.0	0.0	0.0	
		6	Combi	ined SOx/NO	Dx Control		0.0	0.0	0.0	0.0	
		7	CO2 C	apture			0.0	0.0	0.0	0.0	
		8	Subto	tal			0.0	0.0	0.0	0.0	
		9	Base F	lant			459.2	975.4	113.3	36.62	
		10	Emissi	ion Taxes			0.0	0.0	0.0	0.0	
		11	Total				459.2	975.4	113.3	36.62	
		12									
		13									
		14									
		15									
	Process	Tune		erall Diau				Costs are in (	Constant 2003 d	ollars.	

Combustion Overall Plant Cost Summary result screen.

The **Cost Summary** result screen displays costs associated with the power plant as a whole. The costs summarized on this screen are expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each technology (row) is described briefly below.

**Combustion NO_x Control:** The total cost of the In-Furnace  $NO_x$  controls used.

- **Post-Combustion NO**_x **Control:** The total cost of all the Post-Combustion NO_x removal modules used.
- Mercury Control: The total cost of all the mercury control modules used.
- **TSP Control:** The total cost of all the conventional particulate removal modules used.
- $SO_2$  Control: The total cost of all the  $SO_2$  conventional removal modules used.
- **Combined SO_x/NO_x:** The total cost of all the combined SO_x/NO_x advanced removal modules used.
- **Subtotal:** This is the cost of the conventional and advanced abatement technology modules alone. This is the total abatement cost. The subtotal is highlighted in yellow.
- **Base Plant:** The total cost of the base plant without consideration of any abatement technologies. This can be used to compare with other power plant types.
- **Total:** This is the total cost of the entire power plant. This result is highlighted in yellow.

Each cost category (column) is described briefly below.

- **Capital Required:** The total capital requirement (TCR). This is the money that is placed (capitalized) on the books of the utility on the service date. The total cost includes the total plant investment plus capitalized plant startup. Escalation and allowance for funds used during construction (AFUDC) are also included. The capital cost is given on both a total and an annualized basis.
- **Revenue Required:** Amount of money that must be collected from customers to compensate a utility for all expenditures in capital, goods, and services. The revenue requirement is equal to the carrying charges plus expenses. The revenue required is given on both an annualized and a net power output basis.

# **Overall NGCC Plant**

The input parameter screens described in the following sections are available when the **Combustion (Turbine)** is selected as the plant type from the **New Session** pull down menu. These screens apply to the power plant as a whole, not to specific technologies.

# **Overall NGCC Plant Diagram**



Overall NGCC Plant – Diagram input screen

The **Overall NGCC Plant Diagram** appears in the **Configure Plant**, **Set Parameters** and in the **Get Results** program area. The screen displays the plant configuration settings on the left side of the page and a diagram of the configured plant on the right of the page. No input parameters or results are displayed on this screen.

### **Overall NGCC Plant Performance Inputs**

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2			<u>(</u>	<u>C</u> onfigure Pla	nt	Γ	Se	t <u>P</u> ara	mete	ers	Ĩ		Get Res	ults	
		Ove; Plai	<u>r</u> all nt	F <u>u</u> el	Power <u>B</u> lock	NC	Dx Control	C <u>O</u> 2 Ca	apture	By-Prod. Mgmt	Ì	Stac <u>k</u>			
9				T	itle		Unit	s	Unc	Value	Calc	Min	Max	Default	
6			1	Capacity Factor			%			75.00		0.0	100.0	75.00	
3			2												
1		-	3	Gross Electrical C	Dutput		MW	g		516.9		100.0	2000	calc	
्रा		-	4	Net Electrical Out	tput		MV	/		506.5	M	100.0	2500	calc	
		-	5	(MW output for	r reference only	r)									
		-	6	Ambient Air Tem		_	917			77.00		60.00	120.0	77.00	
Z		-	/ 0	Ambient Air Fred	iperature	-	r nei	•		14.70		12.00	15.00	14.70	
21		-	0	Ambient Air Hun	niditar	-	1h H2O/lb	drv air		1 800e-02		0.0	3 000e-02	1 800e-02	
?		-	10			-				10000-02		0.0			
-1			11	See Power .	Block tab for										
			12	additional	parameters										
		Ĩ	13												
			14												
			15												
			16												
		-	17			_									
		P	18 Proc	ess Type: Ove	rall Plant			Y							
			. Di	agram <u>2</u> .1	Performance	K	<u>3</u> . Constrai	nts /	<u>4</u> .	Financing	<u> </u>	<u>5</u> . O&M C	ost / <u>6</u>	. Emis. Taxes	Z

Overall NGCC Plant – Performance input screen.

The parameters available on this screen establish the plant availability, electrical requirements, and ambient conditions for the power plant. These parameters have a major impact on the performance and costs of each of the individual technologies.

- **Capacity Factor:** This is an annual average value, representing the percent of equivalent full load operation during a year. The capacity factor is used to calculate annual average emissions and materials flows.
- **Gross Electrical Output:** This is the gross output of the generator in megawatts (MWg). The value does not include auxiliary power requirements. The model uses this information to calculate key mass flow rates. The value here is shown for reference only. The value is controlled primarily by the number of gas turbines selected from the **Power Block** tab.
- **Net Electrical Output:** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties). The value cannot be changed and is shown for reference only.
- **Ambient Air Temperature:** This is the inlet temperature of the ambient combustion air prior to entering the preheater. The model presumes an *annual average* temperature. Inlet air temperature affects the boiler energy balance and efficiency. It provides a reference point for the calculation of pressure throughout the system. Currently, the model cannot have temperatures below 77F.
- **Ambient Air Pressure:** This is the absolute pressure of the air inlet stream to the boiler. The air pressure is used to convert flue gas molar flow rates to volume flow rates. The default value is 14.7 psia.

**Ambient Air Humidity:** This is the water content of the inlet combustion air. This value is used in calculating the total water vapor content of the flue gas stream. The value is referred to as the specific humidity ratio, expressed as a ratio of the water mass to the dry air mass. The default value is 0.018.

### **Overall NGCC Plant Constraints Inputs**

The **Constraints** input parameters define the emission constraints as they apply to the gases emitted from the power plant. Constraints for sulfur dioxide, nitrogen dioxides, particulates, and mercury are not needed due to the cleaner emissions from NGCC plants.

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ъſ	<b>. F</b> -	Untitled*									_	
0		<u>(</u>	<u>C</u> onfigure Pla	ant ]	Set	<u>P</u> aramet	ers	Ĩ		Get Res	sults	
		Ove <u>r</u> ali Plant	F <u>u</u> el	Power <u>B</u> lock	<u>N</u> Ox Control	C <u>O</u> 2 Capture	By-Prod Mgmt		Stac <u>k</u>			_
9	Ш		Т	litle	Units	Unc	Value	Calc	Min	Max	Default	
К	Ш	1										
3	Ш	2	Total CO2 Remov	val Constraint	%		90.00		0.0	99.00	90.00	
	Ш	4	Total CO2 Relito	varconstraint	70		50.00		0.0	33.00	30.00	
PT	Ш	5										
	Ш	6										
	Ш	7										
	Ш	9						-				
?	Ш	10										
	Ш	11										
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	Ш	14										
	Ш	15										
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		17										
		Proce	ess Type: Ove	erall Plant		-		1				
		<u>1</u> . Dia	agram 🖌 <u>2</u> .	Performance	<u>3</u> . Constrain	ts <u>4</u> .	Financing		<u>5</u> . O&M C(	ost 🖌 !	<u>6</u> . Emis. Taxes	

Overall NGCC Plant – Emission Constraints input screen.

The emission constraints determine the removal efficiencies of control systems that capture  $CO_2$ . The level of capture is set to comply with the specified emission constraints. As discussed later, however, user-specified values for control technology performance may cause the plant to over-comply or under-comply with the emission constraints specified in this screen. Each parameter is described briefly below.

**Total CO₂ Removal Constraint:** The emission constraint applies to all the air emission sources in the power plant, primary or secondary. The default value is based on recent discussions and is not based on any currently enforced law.

### **Overall NGCC Plant Financing Inputs**

Inputs for the financing costs of the base plant itself are entered on the **Financing** input screen.

Configure Plant         Sct Parameters         Get Results           Overall Plant         Fuel         Power Block         NOx Control         CQ2 Capture         Prod Mgmt         Stack           Image: Constant or Current Dollars?         Constant or Current Dollars?         Constant or Current Dollars?         Menu         Menu         Menu         Constant           Image: Constant or Current Dollars?         Constant or Current Dollars?         Constant or Constant         0.1030         0.0         2.000         cale           Image: Constant or Current Dollars?         Constant or Constant         Image: Constant or Current Dollars?         Constant or Constant         Menu         Menu         Constant           Image: Constant or Current Dollars?         Constant or Constant         Menu         Menu         Constant         Constant           Image: Constant or Current Dollars?         Constant         0.1480         Image: Constant         Menu         Menu         Constant           Image: Constant or Project Book Life         years         30.00         5.000         6.000         30.00           Real Preferred Stock Return         %         9.000         0.0         15.00         9.000           Image: Common Stock Return         %         45.00         0.0         10.00         10.00<		n a si				<u> </u>			
Fuel         Power Block         Mox Control         CQ2 Capture         Pgc,Prod. Mgmt         Stack           1         Year Costs Reported         2003 ×         Menu         Menu         2003           2         Constant or Current Dollars?         Constant ×         Menu         Menu         Menu         Constant ×           3         Discount Rate (Before Taxes)         fraction         0.1030         ✓         0.0         2.000         cale           4         Fixed Charge Factor (PCF)         fraction         0.1480         ✓         0.0         2.000         cale           5         Or, specify all the following:         -         -         -         -         -           6         Inflation Rate         %/yr         0.0         ✓         0.0         20.00         cale           7         Plant or Project Book Life         years         30.00         5.000         60.00         30.00           8         Real Bond Interest Rate         %         9.000         0.0         12.00         10.00         12.00           10         Real Common Stock Return         %         45.00         0.0         10.00         10.00           11         Percent Equity (Prefered Stock)	<u>(</u>	Configure Plant	Set <u>P</u> ar	amet	ers			<u>G</u> et Re:	sults
Title         Units         Unc         Value         Calc         Min         Max         Default           1         Year Costs Reported         2003 ▼         Menu         Menu         2003         2003         Constant or Current Dollars?         Menu         Menu         2003         2003         Constant or Current Dollars?         Menu         Menu         Constant or Current Dollars?         Menu         Menu         Constant or Current Dollars?         Menu         Menu         Constant or Current Dol         Constant or Current Dol         Constant or Current Dol         Constant or Current Suite         Constant or Current Suite         Constant or Current Suite         Constant or Current Suite         Menu         Menu         Constant or Current Dolars?         Menu         Menu         Constant or Current Suite         Menu         Menu         Menu         Constant or Criptic Bock Life         Years         0.0         Menu         Menu         Menu         Menu         Menu         Menu         Menu	Ove <u>r</u> all Plant	Fuel Power Block	<u>N</u> Ox Control CO2 C	apture	By-Prod. Mgmt	Ì	Stac <u>k</u>		
I         Year Costs Reported         2003         Menu         Menu         Menu         2003           2         Constant or Current Dollars?         Constant or Current Dollars?         Constant or Current Dollars?         Menu         Menu         Constant         Menu         Menu         Constant           3         Discount Rate (Before Taxes)         fraction         0.1030         ✓         0.0         2.000         calc           4         Fixed Charge Factor (FCF)         fraction         0.1480         ✓         0.0         1.000         calc           5         Or, specify all the following:         0.0         ✓         0.0         20.00         calc           6         Inflation Rate         %/yr         0.0         ✓         0.00         15.00         9.000           7         Plant or Project Book Life         years         30.00         5.000         60.00         30.00           8         Real Bond Interest Rate         %         9.000         0.0         15.00         9.000           9         Real Common Stock Return         %         45.00         0.0         10.00         10.00           10         Real Common Stock Neturn         %         45.00         0.0		Title	Units	Unc	Value	Calc	Min	Max	Default
2         Constant or Current Dollars?         Menu         Menu         Menu         Menu         Menu         Constant           3         Discount Rate (Before Taxes)         fraction         0.1030         ✓         0.00         2.000         calc           4         Fixed Charge Factor (FCF)         fraction         0.1180         ✓         0.00         1.000         calc           5 <i>Or, specify all the following:</i> 0.0         0.00         ½         0.0         20.00         calc           6         Inflation Rate         %/yr         0.0         ½         0.0         20.00         calc           7         Plant or Project Book Life         years         30.00         5.000         60.00         30.00           8         Real Bond Interest Rate         %         9.000         0.0         12.00         20.00         8.500           10         Real Common Stock Return         %         45.00         0.00         10.00         45.00           11         Percent Equity (Preferred Stock)         %         45.00         0.00         10.00         calc           12         Percent Equity (Common Stock)         %         45.00         10.00         10.00	1	Year Costs Reported			2003 🔹		Menu	Menu	2003
3         Discourt Rate (Before Taxes)         fraction         0.1030         ✓         0.0         2.000         calc           4         Fixed Charge Factor (PCF)         fraction         0.1430         ✓         0.0         1.000         calc           5         Or, specify all the following:	2	Constant or Current Dollars?			Constant 🔻		Menu	Menu	Constant
4         Fixed Charge Factor (FCF)         fraction         0.1480         ✓         0.0         1.000         calc           5         Or, specify all the following:         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -	3	Discount Rate (Before Taxes)	fraction		0.1030	M	0.0	2.000	calc
5         Or, specify all the following:         -         -         -           6         Inflation Rate         %/yr         0.0         ✔         0.0         20.00         calc           7         Plant or Project Book Life         years         30.00         5.000         60.00         30.00           8         Real Bond Interest Rate         %         9.000         0.0         15.00         9.000           9         Real Preferred Stock Return         %         8.500         0.0         20.00         8.500           10         Real Common Stock Return         %         45.00         0.0         12.00         12.00         10.00         45.00           12         Percent Equity (Preferred Stock)         %         10.00         0.0         10.00         45.00           13         Percent Equity (Common Stock)         %         45.00         ✔         0.0         10.00         calc           14	4	Fixed Charge Factor (FCF)	fraction		0.1480	K	0.0	1.000	calc
6         Inflation Rate         %/yr         0.0         ☑         0.0         20.00         calc           7         Plant or Project Book Life         years         30.00         5.000         60.00         30.00           8         Real Bond Interest Rate         %         9.000         0.0         15.00         9.000           9         Real Preferred Stock Return         %         8.500         0.0         22.00         8.500           10         Real Common Stock Return         %         45.00         0.0         12.00         12.00           11         Percent Equity (Preferred Stock)         %         45.00         0.0         100.0         45.00           12         Percent Equity (Common Stock)         %         45.00         0.0         100.0         calc           13         Percent Equity (Common Stock)         %         35.00         15.00         50.00         35.00           14             0.0         10.00         4.000           15         Federal Tax Rate         %         35.00         15.00         50.00         35.00           16         State Tax Rate         %         4.000         0.0	5	Or, specify all the following:							
7         Plant or Project Book Life         years         30,00         5,000         60,00         30,00           8         Real Bond Interest Rate         %         9,000         0.0         15,00         9,000           9         Real Prefered Stock Return         %         8,500         0.0         22,00         8,500           10         Real Common Stock Return         %         45,00         0.0         100.0         45,00           11         Percent Debt         %         45,00         0.0         100.0         45,00           12         Percent Equity (Preferred Stock)         %         45,00         0.0         100.0         10,00           13         Percent Equity (Common Stock)         %         45,00         10         0.0         26,00           14	6	Inflation Rate	%/yr		0.0	V	0.0	20.00	calc
8         Real Bond Interest Rate         %         9,000         0.0         15.00         9,000           9         Real Prefered Stock Return         %         8,500         0.0         25.00         8,500           10         Real Common Stock Return         %         12,00         0.0         25.00         12.00           11         Percent Debt         %         45.00         0.0         100.0         45.00           12         Percent Equity (Preferred Stock)         %         10.00         0.0         100.0         10.00           13         Percent Equity (Common Stock)         %         45.00         ⊻         0.0         100.0         calc           14             50.00         35.00         10.00         calc           14              50.00         35.00         10.00         calc           14            35.00         10.00         50.00         35.00           15         Federal Tax Rate         %         4.000         0.0         10.00         4.000           16         State Tax Rate         %         2.00	7	Plant or Project Book Life	years		30.00		5.000	60.00	30.00
9         Real Preferred Stock Return         %         8.500         0.0         20.00         8.500           10         Real Common Stock Return         %         12.00         0.0         25.00         12.00           11         Percent Debt         %         45.00         0.0         100.0         45.00           12         Percent Equity (Preferred Stock)         %         10.00         0.0         100.0         10.00           13         Percent Equity (Common Stock)         %         45.00         ✓         0.0         100.0         calc           14              50.0         50.00         35.00           15         Federal Tax Rate         %         35.00         15.00         50.00         35.00           16         State Tax Rate         %         4.000         0.0         10.00         4.000           17         Property Tax Rate         %         0.0         0.0         2.000         0.0           18         Investment Tax Credit         %         0.0         0.0         20.00         0.0	8	Real Bond Interest Rate	%		9.000		0.0	15.00	9.000
10         Real Common Stock Return         %         12.00         0.0         25.00         12.00           11         Percent Debt         %         45.00         0.0         100.0         45.00           12         Percent Debt         %         45.00         0.0         100.0         45.00           13         Percent Equity (Common Stock)         %         45.00         ✔         0.0         100.0         calc           14                                                                              <	9	Real Preferred Stock Return	%		8.500		0.0	20.00	8.500
I1         Percent Debt         %         45.00         0.0         100.0         45.00           I2         Percent Equity (Preferred Stock)         %         10.00         0.0         10.00         10.00           I3         Percent Equity (Common Stock)         %         45.00         10         0.0         10.00         calc           I4         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -	10	Real Common Stock Return	%		12.00		0.0	25.00	12.00
12       Percent Equity (Preferred Stock)       %       10.00       0.0       100.0       10.00         13       Percent Equity (Common Stock)       %       45.00       ✓       0.0       100.0       calc         14	11	Percent Debt	%		45.00		0.0	100.0	45.00
13         Percent Equity (Common Stock)         %         45.00         ⊻         0.0         100.0         calc           14	12	Percent Equity (Preferred Stock)	%		10.00		0.0	100.0	10.00
14         %         35.00         50.00         35.00           15         Federal Tax Rate         %         35.00         10.00         50.00         35.00           16         State Tax Rate         %         4.000         0.0         10.00         4.000           17         Property Tax Rate         %         2.000         0.0         5.000         2.000           18         Investment Tax Credit         %         0.0         0.0         20.00         0.0	13	Percent Equity (Common Stock)	%		45.00	V	0.0	100.0	calc
15         Federal Tax Rate         %         35,00         15.00         50.00         35,00           16         State Tax Rate         %         4,000         0.0         10.00         4,000           17         Property Tax Rate         %         2,000         0.0         5,000         2,000           18         Investment Tax Credit         %         0.0         0.0         20.00         0.0	14								
16         State Tax Rate         %         4.000         0.0         10.00         4.000           17         Property Tax Rate         %         2.000         0.0         5.000         2.000           18         Investment Tax Credit         %         0.0         0.0         20.00         0.0	15	Federal Tax Rate	%		35.00		15.00	50.00	35.00
17         Property Tax Rate         %         2.000         0.0         5.000         2.000           18         Investment Tax Credit         %         0.0         0.0         20.00         0.0	16	State Tax Rate	%		4.000		0.0	10.00	4.000
18         Investment Tax Credit         %         0.0         0.0         20.00         0.0	17	Property Tax Rate	%		2.000		0.0	5.000	2.000
	18	Investment Tax Credit	%		0.0		0.0	20.00	0.0

Overall NGCC Plant – Financing input screen.

This screen describes the factors required to determine the carrying charge for all capital investments. The carrying charge is defined as the revenue required for the capital investment. The total charge can also be expressed as a levelized cost factor or fixed charge factor. The fixed charge factor is a function of many items. The fixed charge factor can be specified directly or calculated from the other input quantities below it on the financial input screen.

Each parameter is described briefly below.

- **Year Costs Reported:** This is the year in which all costs are given or displayed, both in the input screens and the results. A cost index is used by the IECM to scale all costs to the cost year specified by this parameter. The cost year is reported on every input and result screen associated with costs throughout the interface.
- **Constant or Current Dollars:** Constant dollar analysis does not include the affect of inflation, although real escalation is included. Current dollar analysis includes inflation and real escalation. This choice allows you to choose the mode of analysis for the entire IECM economics. The cost basis is reported on every input and result screen associated with costs throughout the interface.
- **Discount Rate (Before Taxes):** This is also known as the "cost of money". It is the return required by investors in order to attract investment capital. It is equal to the weighted sum of the return on debt and equity. It is the time value of money or the discount rate used in present worth arithmetic.
- **Fixed Charge Factor (FCF):** The fixed charge factor is one of the most important parameters in the IECM. It determines the revenue required to finance the power plant based on the capital expenditures. Put another way, it is a levelized factor which accounts for the revenue per dollar of total plant cost that must be collected from customers in order to pay the carrying charges on that capital investment.

One may specify a fixed charge factor, or fill in the following inputs and the model will calculate the FCF based on them:

- **Inflation Rate:** This is the rise in price levels caused by an increase in the available currency and credit without a proportionate increase in available goods or services. It does not include real escalation.
- **Plant or Project Book Life:** This is the years of service expected from a capital investment. It is also the period over which an investment is recovered through book depreciation.
- **Real Bond Interest Rate:** This is a debt security associated with a loan or mortgage. It is the most secure form of security but the lowest in its return.
- **Real Preferred Stock Return:** This equity security is the second most speculative type and pays the second highest rate of return. The holder of the stock is a part owner of the company.
- **Real Common Stock Return:** This is the most speculative type of equity security sold by a utility and pays the highest relative return. The holder of the stock is a part owner of the company.
- **Percent Debt:** This is the percent of the total capitalization that is associated with debt money. This includes loans and mortgage bonds.
- **Percent Equity (Preferred Stock):** This is the percent of the total capitalization that is associated with the sale of preferred stock.
- **Percent Equity (Common Stock):** This value is the remainder of the capitalization, calculated as 100% minus the percent debt, minus the percent equity in preferred stock.
- **Federal Tax Rate:** This is the federal tax rate. It is used to calculate the amount of taxes paid and deferred.
- **State Tax Rate:** This is the state tax rate. It is used to calculate the amount of taxes paid and deferred.
- **Property Tax Rate:** The property tax rate, or ad valorem, is used to calculate the carrying charge.
- **Investment Tax Credit:** This is an immediate reduction in income taxes equal to a percentage of the installed cost of a new capital investment. It is zero by default. It is used to set the initial balance and the book depreciation.

### **Overall NGCC Plant O&M Cost Inputs**

This screen combines the variable O&M unit costs from all the model components and places them in one spot. These values will also appear in the technology input screens where they are actually used. Values changed on this screen will reflect exactly the same change everywhere else they appear. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

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Overall Plant Fuel Power Block	NOx Control CO2 (	Capture	By-Prod. Mgmt		Stac <u>k</u>		
Title	Units	Unc	Value	Calc	Min	Max	Default
<ol> <li>Internal COE for Comp. Allocation</li> </ol>	15		Base Pla ▼		Menu	Menu	se Plant (u
2 Internal Electricity Price	\$/MWh		53.01		0.0	200.0	calc
3							
4 Natural Gas Cost	\$/mscf		5.346		0.0	10.00	calc
5 Water Cost	\$/1000 gai		0.8316		0.0	2.500	calc
6							
7 Limestone Cost	\$/ton		19.64		0.0	30.00	calc
8 Lime Cost	\$/ton		72.01		40.00	90.00	calc
9 AmmoniaCost	\$/ton		248.2		100.0	400.0	calc
10 UreaCost	\$/ton		412.4		200.0	400.0	calc
11 MEA Cost	\$/ton		1293		0.0	1.500e+04	calc
12 Activated Carbon Cost	\$/ton		1322		500.0	5000	calc
13 Caustic (NaOH) Cost	\$/ton		624.7		0.0	2000	calc
14							
15 Operating Labor Rate	\$/hr		24.82		0.0	100.0	24.82
16							
17							
18							

Overall NGCC Plant – O&M Cost input screen.

- **Internal COE for Comp. Allocations:** This is a pop-up selection menu that determines the method for determining electricity costs within the power plant. The selection of this pop-up menu determines the actual internal electricity price on the next line. The options are
  - Base Plant (uncontrolled)
  - User Specified
  - Total Plant COE
- **Internal Electricity Price:** This is the price of electricity and is calculated as a function of the utility cost of the base plant. The base plant for the **Combustion (Turbine)** model is assumed to be the natural gas supply, power block, and stack. This value is calculated and provided for reference purposes only unless **User Specified** is selected in the pop-up in the previous line.
- As-Delivered Coal Cost: This is the cost of the coal as-delivered.
- **Natural Gas Cost:** This is the cost of natural gas in dollars per thousand standard cubic feet.
- Water Cost: This is the cost of water in dollars per thousand gallons.
- **Limestone Cost:** This is the cost of limestone in dollars per ton.
- Lime Cost: This is the cost of lime in dollars per ton.
- Ammonia Cost: This is the cost of ammonia in dollars per ton.
- **Urea Cost:** This is the cost of natural gas in dollars per ton.
- **MEA Cost:** This is the cost of MEA in dollars per ton.
- Activated Carbon Cost: This is the cost of activated carbon in dollars per ton.

**Caustic (NaOH) Cost:** This is the cost of caustic (NaOH) gas in dollars per ton.

**Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

## **Overall NGCC Plant Emis. Taxes Inputs**

This screen allows users to specify emission taxes or credits as part of the overall plant cost economics. Taxes or credits are typically provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

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3			T	itle		Units	Unc	Value	Calc	Min	Max	Default	
6	Ш	1	Tax on 1	Emissions									
	Ш	2	Sulfur Dioxide (S	C2)		\$/ton		0.0		0.0	5000	0.0	
	Ш	3	Nitrogen Oxide (e	quiv. NO2)		\$/ton		0.0		0.0	5000	0.0	
	Ш	4	Carbon Dioxide (	CO2)		\$/ton		0.0		0.0	5000	0.0	
	Ш	5											
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Emission Constraint Emission Taxes input screen.

The **Emis. Taxes** input screen allows the user to enter the taxes on emissions in dollars per ton. The final costs determined from these inputs are available under the stack tab in the results section of the IECM. The costs are added to the overall plant cost, not a particular technology.

#### Tax on Emissions

- Sulfur Dioxide (SO₂): The user may enter a cost to the plant of emitting sulfur dioxide in dollars per ton.
- Nitrogen Oxide (equiv. NO₂): The user may enter a cost to the plant of emitting nitrogen oxide in dollars per ton.
- **Carbon Dioxide (CO₂):** The user may enter a cost to the plant of emitting carbon dioxide in dollars per ton.

### **Overall NGCC Plant Performance Results**

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<i>∯</i> ∦ ₽∎			Performance Parameter	,	Value		Plant Ene	rgy Requirements	Value
ß	Ш	1	Net Electrical Output (MW)		381.0	1	Turbine Generato	r Output (MW)	974.2
1	Ш	2				2	Air Compressor U	Jse (MW)	506.2
	Ш	3				3	Turbine Shaft Lo	sses (MW)	9.360
•	Ш	4	Auxiliary Fuel Power Input (MBtu/hr	)	0.0	4	Net Turbine Out	put (MW)	462.3
	Ш	5	Total Plant Power Input (MBtu/hr)		3233	5	Misc. Power Bloc	k Use (MW)	9.246
21	Ш	6				6	Absorption CO2	Capture Use (MW)	72.02
2	Ш	7	Gross Plant Heat Rate, HHV (Btu/kW	'h)	6994	7	Aux. Power Prod	aced (MW)	0.0
<u>.                                    </u>	Ш	8	Net Plant Heat Rate, HHV (Btu/kWh)		8485	8	Net Electrical O	ıtput (MW)	381.0
	Ш	9				9			
	Ш	10	Annual Operating Hours (hours)		6575	10			
	Ш	11	Annual Power Generation (BkWh/yr)	ı 1	2.505	11			
	Ш	12				12			
	Ш	13	Net Plant Efficiency, HHV (%)		40.21	13			
	Ш	14				14			
	Ш	15				15			
		Pro	cess Type: Overall Plant		V				
			1. Diagram 🔒 2. Plant Perf.	<u>3</u> . Mass	s In/Out	4.0	Jas Emissions 🖌	5. Total Cost	6. Cost Summary

Overall NGCC Plant – Performance results screen.

The **Plant Perf.** result screen displays performance results for the plant as a whole. Heat rates and power in and out of the power plant are given. Each result is described briefly below.

#### **Performance Parameter**

- **Net Electrical Output:** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).
- **Aux. Fuel Power Input:** This is the fuel energy input for the auxiliary natural gas boiler if used with the Amine System. This is additional fuel energy used by the plant, given on an hourly basis. This rate is also referred to as the auxiliary fuel power input.
- **Total Plant Power Input:** This is the total of all the fuel energy used by the plant, given on an hourly basis (maximum capacity). This rate is also referred to as the total plant power input.
- **Gross Plant Heat Rate, HHV:** This is the gross heat rate of the entire plant.
- **Net Plant Heat Rate, HHV:** This is the net heat rate of the entire plant (including aux power produced) which includes the effect of plant equipment and pollution control equipment.
- **Annual Operating Hours:** This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.

- **Annual Power Generation:** This is the net annual power production of the plant. The capacity factor and all energy credits or penalties are used in determining its value.
- Net Plant Efficiency, HHV: This is the net efficiency of the entire plant.

#### **Plant Power Requirements**

A second group of results provide a breakdown of the internal power consumption for the individual technology areas. These are all given in units of megawatts. Individual plant sub-components will only be displayed when they are configured in the **Configure Plant** section of the model.

- Turbine Generator Output: This is the power generated by the turbine.
- Air Compressor Use: The power required to operate the air compressor.
- **Turbine Shaft Losses:** This value accounts for any turbine electricity losses other than power used for the air compressor.
- **Net Turbine Output:** This if the net power generated by the turbine. This is the gross output of the turbine minus the power required by the air compressor and any miscellaneous losses.
- **Misc. Power Block Use:** This is the power required to operate pumps and motors associated with the power block area.
- **Absorption CO₂ Capture Use:** If a  $CO_2$  Capture system is in use, this is the power required to operate the system.
- **Aux. Power Produced:** If an auxiliary natural gas boiler is used to provide steam and power, this is the additional power that it produces.
- **Net Electrical Output:** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

### **Overall NGCC Plant Mass In/Out Results**

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			Configure Plant		Set Pa	ame	ters	Get 1	Results
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	ſ		Chemical biputs	FI (i	low Rate tons/hr)		Solid &	Liquid Outputs	Flow Rate (tons/hr)
	I	1	Coal		0.0	1	Slag		0.0
	Ш	2	Oil		0.0	2	Ash Disposed		0.0
111	Ш	3	Natural Gas		74.37	3	Scrubber Solids E	)isposed	0.4462
	Ш	4	Petroleum Coke		0.0	4	Particulate Emissi	ons to Air	0.0
	Ш	5	Other Fuels		0.0	5	Captured CO2		184.6
	Ш	6	Total Fuels		74.37	6	By-Product Ash 3	Sold	0.0
	Ш	7				7	By-Product Gyps	um Sold	0.0
	Ш	8	Lime/Limestone		0.0	8	By-Product Sulfu	r Sold	0.0
Ш	Ш	9	Sorbent		0.3815	9	By-Product Sulfu	ric Acid Sold	0.0
Ш	Ш	10	Ammonia		0.0	10	Total		185.0
	I	11	Activated Carbon	1.	384e-02	11			
	I	12	Other Chemicals, Solvents & Catalyst		0.0	12	See Tab		
Ш	Ш	13	Total Chemicals	1	0.3954	13			
Ш	Ш	14				14			
	Ш	15	Process Water		0.0	15			
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	Ν	、	<u>1</u> . Diagram 🖌 <u>2</u> . Plant Perf. 🗼	<u>3</u> . Mas	s In/Out	4.	3as Emissions 🖌	<u>5</u> . Total Cost /	<u>6</u> . Cost Summary

Overall NGCC Plant – Mass In/Out results screen.

#### **Chemical Inputs**

**Coal:** Flow rate of coal used in the power plant.

**Oil:** Flow rate of oil used in the power plant

Natural Gas: : Flow rate of natural gas used in the power plant

Petroleum Coke: Total mass of petroleum coke used in the power plant

- **Other Fuels:** Flow rate of other fuels used in the power plant
- **Total Fuels:** This is the flow rate of fuel entering the power plant. This result is highlighted in yellow.
- Lime/Limestone: Total mass of this reagent used in the power plant on a wet basis.
- Sorbent: Total mass of sorbent used in the power plant
- Ammonia: Total mass of ammonia used in the power plant.
- Activated Carbon: Flow rate of activated carbon injected in the power plant.
- **Other Chemicals, Solvents & Catalyst:** Flow rate of other chemicals, solvents and catalysts used in the power plant.
- **Total Chemicals:** Flow rate of reagent entering the power plant. This result is highlighted in yellow.
- Process Water: Flow rate of water used in the power plant.

#### Solid & Liquid Outputs

**Slag:** Flow rate of slag from the power plant on a dry basis.

Ash Disposed: Flow rate of ash from the power plant on a dry basis.

- **Scrubber Solids Disposed:** Flow rate of scrubber treatment solid wastes from the power plant on a dry basis.
- **Particulate Emissions to Air:** Solids that remain in the flue gas and exit the plant are reported on a mass basis.
- Captured CO₂: Flow rate of the captured CO₂.
- **Byproduct Ash Sold:** Flow rate of ash (bottom and fly ash) sold in commerce as a by-product on a dry basis.
- **Byproduct Gypsum Sold:** Flow rate of flue gas treatment solids sold in commerce as a by-product on a dry basis.
- **Byproduct Sulfur Sold:** Flow rate of elemental sulfur recovered from flue gas and sold in commerce as a by-product on a dry basis.
- **Byproduct Sulfuric Acid Sold:** Total mass of sulfuric acid recovered from the flue gas and sold in commerce as a by-product.
- **Total:** This is the total wet solid mass exiting the power plant. This result is highlighted in yellow.

#### **Overall NGCC Plant Gas Emissions Results**

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*			Stack Gas Component	Flow Rate (tons/hr)		Stack (	3as Component	Flow Rate (tons/hr)
ß		1	Nitrogen (N2)	2664	1	Total SOx (equiva	lent SO2)	0.0
e l		2	Oxygen (O2)	521.3	2	Total NOx (equive	alent NO2)	5.101e-02
		3	Water Vapor (H2O)	156.4	3			
•		4	Carbon Dioxide (CO2)	20.51	4			
		5	Carbon Monoxide (CO)	0.0	5			
<u> ?</u> ]		6	Hydrochloric Acid (HCl)	0.0	6			
2		7	Sulfur Dioxide (SO2)	0.0	7			
-		8	Sulfuric Acid (equivalent SO3)	0.0	8			
		9	Nitric Oxide (NO)	3.201e-02	9			
		10	Nitrogen Dioxide (NO2)	1.937e-03	10			
		11	Ammonia (NH3)	7.887e-04	11			
		12	Argon (Ar)	0.0	12	Use Result Tools	under View	
		13	Total Gases	3363	13	menu for alternat	e units	
		14			14			
		15			15			
		Pro	cess Type: Overall Plant	<b>_</b>				
	ľ		1. Diagram <u>2</u> . Plant Perf.	( <u>3</u> . Mass In/Out	4.0	3as Emissions 📈	<u>5</u> . Total Cost	<u>6</u> . Cost Summary /

Overall NGCC Plant – Gas Emissions result screen.

#### **Stack Gas Component**

Each result is described briefly below:

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

- Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.
- Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

- Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.
- Ammonia (NH₃): Total mass of ammonia.
- **Argon (Ar):** Argon is present in small quantities in atmospheric air. The argon emitted from the power plant is shown on a mass basis.
- **Total Gases:** Total of the individual components listed above. This item is highlighted in yellow.

Total SO_x (equivalent SO₂): Total mass of SO_x as equivalent SO₂.

Total  $NO_x$  (equivalent  $NO_2$ ): Total mass of  $NO_x$  as equivalent  $NO_2$ .

#### **Overall NGCC Plant Total Cost Results**

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				<u>C</u> onfigure Plant	Ĩ	Set <u>P</u> ara	meters	Ĩ	<u>G</u> et Re	sults
	ľ	On Pi	ze <u>r</u> ai lant	I Fuel Power Bloo	<b>k</b> <u>N</u> Ox Co	ontrol C <u>O</u> 2 Caj	oture By-Pr Mgr	od. nt Stac	<u>k</u>	
*				Technology		Fixed O&M (M\$/yr)	Variable O&M (M\$/yr)	Total O&M (M\$/yr)	Annualized Capital (M\$/yr)	Total Levelized Annual Cost (M\$/yr)
E.			1	CO2 Capture		3.992	43.24	47.23	19.87	67.10
e l			2	Power Block		7.087	81.57	88.66	49.54	138.2
			3	Post-Combustion NOx Control		0.0	0.0	0.0	0.0	0.0
•			4	Subtotal		11.08	124.8	135.9	69.41	205.3
			5	Emission Taxes		0.0	0.0	0.0	0.0	0.0
<u> ?</u>			6	Total		11.08	124.8	135.9	69.41	205.3
?			7							
-			8							
			9							
		-	10							
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		Pr	15 oce: <u>1</u> . ]	ss Type: Overall Plant Diagram <u>2</u> . Plant Perf.	<u>3</u> . M	ass In/Out	Costs : 4. Gas Emissio	are in Constant	2005 dollars. talCost	6. Cost Summary

Overall NGCC Plant – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs associated with the power plant as a whole. Each technology (row) is described briefly below.

#### Technology

 $CO_2$  Capture: The total cost of all the  $CO_2$  Capture modules used.

**Power Block:** The total cost of the power block without consideration of any abatement technologies. The Power Block contains the air compressor, gas turbine, steam turbine and heat recovery steam generator areas.

- **Post-Combustion NO**_x **Control:** The total cost of all the Post-Combustion NO_x removal modules used.
- **Subtotal:** This is the cost of the conventional and advanced abatement technology modules alone. This is the total abatement cost. The subtotal is highlighted in yellow.
- **Emission Taxes:** This is the sum of the user assessed taxes on the plant emissions of  $SO_2$ ,  $NO_x$  and  $CO_2$ .
- **Total:** This is the total cost of the entire power plant. This result is highlighted in yellow.

Each cost category (column) is described briefly below.

- **Fixed O&M:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs for each technology.
- **Variable O&M:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs associated with a technology.
- **Total O&M:** This is the sum of the annual fixed and variable operating and maintenance costs for each technology.
- **Annualized Capital:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow

## **Overall NGCC Plant Cost Summary Results**

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2	<u>c</u>	<u>l</u> on	figure Pla	unt	Se	t <u>P</u> arameter	's	-	<u>G</u> et Results	1
	Overall Plant	Ĩ	F <u>u</u> el	Power <u>B</u> lock	<u>N</u> Ox Control	C <u>O</u> 2 Capture	By-Prod. Mgmt	Stack		
				Technolog	r	Capital Required (M\$)	Capital Required (\$/kW-net)	Revenue Required (M\$/yr)	Revenue Required (\$/MWh)	
3		1	CO2 Captur	re		134.3	310.6	67.10	23.61	
T		2	Power Bloc	k		334.7	774.3	138.2	48.62	
		3	Post-Comb	ustion NOx Cor	itrol	0.0	0.0	0.0	0.0	
		4	Subtotal Encircum			469.0	1085	205.3	72.23	
41		5	Emission 1	axes		0.0	1095	205.2	72.22	
		7	TOTAL			403.0	1003	203.3	72.23	
1		8								
		9								
		10								
		11								
		12								
		13								
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	Process [*] <u>1</u> . Dia	Type	: Overal	l Plant . Plant Perf.	✓ 	0ut <u>4</u> . Gas	Costs are in C	onstant 2005 d <u>5</u> . Total Cos	lollars. t <u>6</u> . Cost Su	mmary

Overall NGCC Plant – Cost Summary results screen.

The **Cost Summary** result screen displays costs associated with the power plant as a whole. Each technology (row) is described briefly below.

#### Technology

- $CO_2$  Capture: This is the capital cost for the equipment that captures  $CO_2$  in the plant.
- **Power Block:** This is the capital cost for the power block process area of the plant.
- **Post-Combustion NO_x Control:** This is the capital cost for the equipment that captures post-combustion  $NO_x$  in the plant.
- **Subtotal:** This is the cost of the conventional and advanced abatement technology modules alone. This is the total abatement cost. The subtotal is highlighted in yellow.
- **Emission Taxes:** This is the sum of the user assessed taxes on the plant emissions of  $SO_2$ ,  $NO_x$  and  $CO_2$ .
- **Total:** This is the sum of all of the above capital costs for all of the process areas in the plant.

Each cost category (column) is described briefly below.

- **Capital Cost:** The total capital requirement (TCR). This is the money that is placed (capitalized) on the books of the utility on the service date. The total cost includes the total plant investment plus capitalized plant startup. Escalation and allowance for funds used during construction (AFUDC) are also included. The capital cost is given on both a total and an annualized basis.
- **Revenue Required:** Amount of money that must be collected from customers to compensate a utility for all expenditures in capital, goods, and services. The revenue requirement is equal to the carrying charges plus expenses. The revenue required is given on both an annualized and a net power output basis.

# **Overall IGCC Plant**

The input parameter screens described in the following sections are available when the **IGCC** is selected as the plant type from the **New Session** pull down menu. These screens apply to the power plant as a whole, not to specific technologies.

# **Overall IGCC Plant Diagram**



Overall IGCC Plant – Diagram screen.

The **Overall IGCC Plant Diagram** appears in the <u>Configure Plant, Set</u> **Parameters** and in the <u>Get Results</u> program area. The screen displays the plant configuration settings on the left side of the page and a diagram of the configured plant on the right of the page. No input parameters or results are displayed on this screen.

## **Overall IGCC Plant Performance Inputs**

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	ſ	Ove <u>r</u> a Plant	11	Fuel	<u>A</u> ir Separation	G	asifier Area	<u>S</u> ulf Remo	ur val	C <u>O</u> 2 Captur	e	Por	wer <u>B</u> lock	By-Prod Mgmt	Sta	.c <u>k</u>
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11		1	L C	Capacity Factor			%			75.00			0.0	100.0	75.00	
		2	2													
L		3	3	Gross Plant Size			MM	7g		613.7	ļ	1	100.0	2000	calc	
		4	1	Net Plant Size			MV	V		537.6	ļ	V	100.0	2000	calc	
L		5	5	(MW output for	r reference only											
I		6	5									_				
L		7	7	Ambient Air Tem	perature	_	°F			77.00			-50.00	130.0	77.00	
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I		9	, , ,	Ambient Air Hum	udity	-	16 H2O/16	dry ar		1.800e-02		_	0.0	3.000e-02	1.800e-02	
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Overall IGCC Plant – Performance input screen.

The parameters available on this screen establish the plant availability, electrical requirements, and ambient conditions for the power plant. These parameters have a major impact on the performance and costs of each of the individual technologies.

- **Capacity Factor:** This is an annual average value, representing the percent of equivalent full load operation during a year. The capacity factor is used to calculate annual average emissions and materials flows.
- **Gross Plant Size:** This is the gross output of the generator in megawatts (MW_g). The value does not include auxiliary power requirements. The model uses this information to calculate key mass flow rates. It is shown here for information only.
- **Net Plant Size:** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties). It is shown here for information only.
- **Ambient Air Temperature:** This is the inlet temperature of the ambient combustion air prior to entering the preheater. The model presumes an *annual average* temperature. Inlet air temperature affects the boiler energy balance and efficiency. It provides a reference point for the calculation of pressure throughout the system. Currently, the model cannot have temperatures below 77°F.
- **Ambient Air Pressure:** This is the absolute pressure of the air inlet stream to the boiler. The air pressure is used to convert flue gas molar flow rates to volume flow rates.
- **Ambient Air Humidity:** This is the water content of the inlet combustion air. This value is used in calculating the total water vapor content of the flue gas stream. The value is referred to as the specific humidity ratio, expressed as a ratio of the water mass to the dry air mass.

### **Overall IGCC Plant Constraints Inputs**

The **Constraints** input parameters define the emission constraints as they apply to the gases emitted from the power plant. Constraints for sulfur dioxide, nitrogen dioxides, carbon dioxide, and mercury are not needed due to the cleaner emissions from IGCC plants.

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6		<u>(</u>	<u>C</u> onfigure Pl	ant		Set <u>P</u> ar	amet	ers	Ĩ		<u>G</u> et Res	sults	
		Ove <u>r</u> all Plant	F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	Ren	lfur 10val	C <u>O</u> 2 Captus	re Po	wer <u>B</u> lock	By-Proc Mgmt	. Sta	ic <u>k</u>
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6	Ш	1					_						
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Overall IGCC Plant – Emission Constraints input screen.

The emission constraints determine the removal efficiencies of control systems that capture particulates. The level of capture is set to comply with the specified emission constraints. As discussed later, however, user-specified values for control technology performance may cause the plant to over-comply or under-comply with the emission constraints specified in this screen. Each parameter is described briefly below.

**Particulate Emission Constraint:** The emission constraint of the total suspended particulates is a function of the fuel type and is used to determine the removal efficiency of particulate control systems (if used).

#### **Overall IGCC Plant Financing Inputs**

Inputs for the financing costs of the base plant itself are entered on the **Financing** input screen.
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ſ	Ove <u>r</u> all Plant	F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulf Remo	ur val	C <u>O</u> 2 Captu:	re Po	wer <u>B</u> lock	By-Proo Mgmt	1. Sta
		Ti	itle	Uni	is	Unc	Value	Calc	Min	Max	Default
I	1	Year Costs Repor	rted				2003 💌		Menu	Menu	2003
I	2	Constant or Curre	ent Dollars?				Constant 🔻		Menu	Menu	Constant
1	3	Discount Rate (B	efore Taxes)	fracti	on		0.1030	M	0.0	2.000	calc
I	4	Fixed Charge Fac	tor (FCF)	fracti	on		0.1480	M	0.0	1.000	calc
I	5	Or, specify all	the following:								
I	6	Inflation Rate		%/3	rr		0.0	M	0.0	20.00	calc
	7	Plant or Project B	ook Life	year	rs		30.00		5.000	60.00	30.00
	8	Real Bond Interes	st Rate	%			9.000		0.0	15.00	9.000
	9	Real Preferred Sto	ock Return	%			8.500		0.0	20.00	8.500
	10	Real Common Sto	ock Return	%			12.00		0.0	25.00	12.00
I	11	Percent Debt		%			45.00		0.0	100.0	45.00
	12	Percent Equity (P	referred Stock)	%			10.00		0.0	100.0	10.00
	13	Percent Equity (C	ommon Stock)	%			45.00	M	0.0	100.0	calc
	14										
	15	Federal Tax Rate		%			35.00		15.00	50.00	35.00
	16	State Tax Rate		%			4.000		0.0	10.00	4.000
I	17	Property Tax Rate	е	%			2.000		0.0	5.000	2.000
	18	Investment Tax C	redit	%			0.0		0.0	20.00	0.0
I	Proc	ess Type: Over	rall Plant		-						

Overall IGCC Plant – Financing input screen.

This screen describes the factors required to determine the carrying charge for all capital investments. The carrying charge is defined as the revenue required for the capital investment. The total charge can also be expressed as a levelized cost factor or fixed charge factor. The fixed charge factor is a function of many items. The fixed charge factor can be specified directly or calculated from the other input quantities below it on the financial input screen.

Each parameter is described briefly below.

- **Year Costs Reported:** This is the year in which all costs are given or displayed, both in the input screens and the results. A cost index is used by the IECM to scale all costs to the cost year specified by this parameter. The cost year is reported on every input and result screen associated with costs throughout the interface.
- **Constant or Current Dollars:** Constant dollar analysis does not include the affect of inflation, although real escalation is included. Current dollar analysis includes inflation and real escalation. This choice allows you to choose the mode of analysis for the entire IECM economics. The cost basis is reported on every input and result screen associated with costs throughout the interface.
- **Discount Rate (Before Taxes):** This is also known as the "cost of money". It is the return required by investors in order to attract investment capital. It is equal to the weighted sum of the return on debt and equity. It is the time values of money on the discount rate used in present worth arithmetic. One may specify a Fixed Charge Factor and Discount Rate, or fill in the following inputs and the model will calculate them.
- **Fixed Charge Factor (FCF):** The fixed charge factor is one of the most important parameters in the IECM. It determines the revenue required to finance the power plant based on the capital expenditures. Put another way, it is a levelized factor which accounts for the revenue per

dollar of total plant cost that must be collected from customers in order to pay the carrying charges on that capital investment.

One may specify a fixed charge factor, or fill in the following inputs and the model will calculate the FCF based on them:

- **Inflation Rate:** This is the rise in price levels caused by an increase in the available currency and credit without a proportionate increase in available goods or services. It does not include real escalation.
- **Plant or Project Book Life:** This is the years of service expected from a capital investment. It is also the period over which an investment is recovered through book depreciation.
- **Real Bond Interest Rate:** This is a debt security associated with a loan or mortgage. It is the most secure form of security but the lowest in its return.
- **Real Preferred Stock Return:** This equity security is the second most speculative type and pays the second highest rate of return. The holder of the stock is a part owner of the company.
- **Real Common Stock Return:** This is the most speculative type of equity security sold by a utility and pays the highest relative return. The holder of the stock is a part owner of the company.
- **Percent Debt:** This is the percent of the total capitalization that is associated with debt money. This includes loans and mortgage bonds.
- **Percent Equity (Preferred Stock):** This is the percent of the total capitalization that is associated with the sale of preferred stock.
- **Percent Equity (Common Stock):** This value is the remainder of the capitalization, calculated as 100% minus the percent debt, minus the percent equity in preferred stock.
- Federal Tax Rate: This is the federal tax rate. It is used to calculate the amount of taxes paid and deferred.
- **State Tax Rate:** This is the state tax rate. It is used to calculate the amount of taxes paid and deferred.
- **Property Tax Rate:** The property tax rate, or ad valorem, is used to calculate the carrying charge.
- **Investment Tax Credit:** This is an immediate reduction in income taxes equal to a percentage of the installed cost of a new capital investment. It is zero by default. It is used to set the initial balance and the book depreciation.

# **Overall IGCC Plant O&M Cost Inputs**

This screen combines the variable O&M unit costs from all the model components and places them in one spot. These values will also appear in the technology input screens where they are actually used. Values changed on this screen will reflect exactly the same change everywhere else they appear. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

C	onfigure Pla	nt Ì	S	et Par	amet	ers	Ĩ		Get Res	ults
Overall Plant	Fuel	<u>A</u> ir Separation	Gasifier Area	Sul Rem	fur oval	C <u>O</u> 2 Captu	re Po	wer <u>B</u> lock	By-Prod Mgmt	Sta
	Т	itle	Un	its	Unc	Value	Calc	Min	Max	Default
1 1	nternal COE for	Comp. Allocation	ns			Base Pla <del>▼</del>		Menu	Menu	se Plant (u
2	nternal Electricit	y Price	\$/IM	Wh		56.21		0.0	200.0	calc
3										
4 1	Natural Gas Cost		\$/n	ıscf		5.346	N	0.0	10.00	calc
5	Water Cost		\$/100	0 gai		0.8316	V	0.0	2.500	calc
6										
7 I	imestone Cost		\$/t	on		19.64		0.0	30.00	calc
<b>8</b> I	ime Cost		\$/t	on		72.01		40.00	90.00	calc
9 4	Ammonia Cost		\$/t	on		248.2		100.0	400.0	calc
10	JreaCost		\$/t	on		412.4		200.0	400.0	calc
11 I	VIEA Cost		\$/t	on		1293		0.0	1.500e+04	calc
12	Activated Carbon	nCost	\$/t	on		1322		500.0	5000	calc
13	Caustic (NaOH) (	Cost	\$/t	on		624.7		0.0	2000	calc
14										
15	Operating Labor	Rate	\$/	hr		24.82		0.0	100.0	24.82
16										
17					_					
18										

Overall IGCC Plant – O& M Cost input screen.

- **Internal COE for Comp. Allocations:** This is a pop-up selection menu that determines the method for determining electricity costs within the power plant. The selection of this pop-up menu determines the actual internal electricity price on the next line. The options are
  - Base Plant (uncontrolled)
  - User Specified
  - Total Plant COE
- **Internal Electricity Price:** This is the price of electricity and is calculated as a function of the utility cost of the base plant. The base plant for the **IGCC** model is assumed to be a coal pile, air separation unit, gasifier, power block, and disposal sites. This value is calculated and provided for reference purposes only unless **User Specified** is selected in the pop-up in the previous line.
- As-Delivered Coal Cost: This is the cost of the coal as-delivered.
- **Natural Gas Cost:** This is the cost of natural gas in dollars per thousand standard cubic feet.
- Water Cost: This is the cost of water in dollars per thousand gallons.
- **Limestone Cost:** This is the cost of limestone in dollars per ton.
- Lime Cost: This is the cost of lime in dollars per ton.
- Ammonia Cost: This is the cost of ammonia in dollars per ton.
- **Urea Cost:** This is the cost of natural gas in dollars per ton.
- **MEA Cost:** This is the cost of MEA in dollars per ton.
- Activated Carbon Cost: This is the cost of activated carbon in dollars per ton.

**Caustic (NaOH) Cost:** This is the cost of caustic (NaOH) gas in dollars per ton.

**Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

# **Overall IGCC Plant Stack Emis. Taxes Inputs**

This screen allows users to specify emission taxes or credits as part of the overall plant cost economics. Taxes or credits are typically provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

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		Overall Plant	Fuel	<u>A</u> ir Separation	Gasifier Area	Rei	ulfur noval	C <u>O</u> 2 Captu	are Po	wer <u>B</u> lock	By-Proo Mgmt	d. Sta	ic <u>k</u>
8			Т	itle		Units	Unc	Value	Calc	Min	Max	Default	
X		1	Tax on I	Emissions									
8		2	Sulfur Dioxide (S	02)		\$/ton		0.0		0.0	5000	0.0	
		3	Nitrogen Oxide (e	equiv. NO2)		\$/ton		0.0		0.0	5000	0.0	
-		4	Carbon Dioxide (	CO2)		\$/ton	_	0.0		0.0	5000	0.0	
		5											
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		Proc	ess Type: Ove	rall Plant		~		Costs are	e in Con	stant 2005	dollars.		
		<u>1</u> . Di	agram <u>2</u> .1	Performance	<u>3</u> .Con	straints	4.	Financing		<u>δ</u> . Ο&Μ Co	st 🔪	<u>6</u> . Emis. Taxe	s

Overall IGCC Plant – Emis. Taxes input screen.

The **Emis. Taxes** input screen allows the user to enter the taxes on emissions in dollars per ton. The final costs determined from these inputs are available under the stack tab in the results section of the IECM. The costs are added to the overall plant cost, not a particular technology.

#### Tax on Emissions

- Sulfur Dioxide (SO₂): The user may enter a cost to the plant of emitting sulfur dioxide in dollars per ton.
- Nitrogen Oxide (equiv. NO₂): The user may enter a cost to the plant of emitting nitrogen oxide in dollars per ton.
- **Carbon Dioxide (CO₂):** The user may enter a cost to the plant of emitting carbon dioxide in dollars per ton.

# **Overall IGCC Plant Performance Results**

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6			<u>C</u> onfigure Pla	ant		Se	t <u>P</u> aı	ame	ters		<u>G</u> et Result	s	Ĩ
	ſ	Ov Pl	erall Fuel ant Fuel	Gas A	sifier rea	<u>S</u> u Ren	lfur 10val	CO2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stack		
*			Performanc	e Parameter		Valu	e		Plant Ene	rgy Requirem	ents	Value	
	Ш	1	Net Electrical Output	(MW)		442.	4	1	Total Generator C	Output (MW)		1015	
1	Ш	2						2	Air Compressor U	Jse (MW)		469.3	
	Ш	3	Total Plant Power In	out (MBtu/hr)		494	)	3	Turbine Shaft Lo	sses (MW)		10.92	
	Ш	4	Gross Plant Heat Rat	e, HHV (Btu/kW	h)	916	3	4	Gross Plant Out	put (MWg)		539.0	
$\Rightarrow$	Ш	5	Net Plant Heat Rate, 1	HHV (Btu∕kWh)		1.117e	+04	5	Misc. Power Bloc	ck Use (MW)		10.78	
91	Ш	6						6	Air Separation U	nit Use (MW)		51.47	
<b>2</b>	Ш	7	Annual Operating Ho	ours (hours)		657	5	7	Gasifier Use (MV	17) 17)		6.731	
<u>~</u>	Ш	8	Annual Power Gener	ation (BkWh/yr)		2.90	9	8	Sulfur Capture U:	se (MW)		4.989	
	Ш	9						9	Claus Plant Use (	MW)		0.4343	
	Ш	10	Net Plant Efficiency,	HHV (%)		30.5	6	10	Beavon-Stretford	Use (MW)		1.321	
	Ш	11						11	Water-Gas Shift I	Reactor Use (IV	(W)	-20.86	
	Ш	12						12	Selexol CO2 Capt	ure Use (MW)		41.70	
	Ш	13						13	Net Electrical O	utput (MW)		442.4	
	Ш	14						14					
	Ш	15						15					
		Pro	ocess Type: Overa	ll Plant		V							
			1. Diagram	2. Plant Perf.	<u>3</u> .1	/lass In/	Out	4.0	3as Emissions 🖌	<u>5</u> . Total Co	st <u>/ 6</u> .Co	st Summary	Z

Overall IGCC Plant – Performance result screen.

The **Plant Perf.** result screen displays performance results for the plant as a whole. Heat rates and power in and out of the power plant are given. Each result is described briefly below.

#### **Performance Parameter**

- **Net Electrical Output:** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).
- **Total Plant Power Input:** This is the total of all the fuel energy used by the plant, given on an hourly basis (maximum capacity). This rate is also referred to as the total plant power input.
- **Gross Plant Heat Rate, HHV:** This is the gross heat rate of the entire plant.
- **Net Plant Heat Rate, HHV:** This is the net heat rate of the entire plant (including aux power produced) which includes the effect of plant equipment and pollution control equipment.
- **Annual Operating Hours:** This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.
- **Annual Power Generation:** This is the net annual power production of the plant. The capacity factor and all power credits or penalties are used in determining its value.
- Net Plant Efficiency, HHV: This is the net efficiency of the entire plant.

#### **Plant Power Requirements**

A second group of results provide a breakdown of the internal power consumption for the individual technology areas. These are all given in units of megawatts. Individual plant sub-components will only be displayed when they are configured in the **Configure Plant** section of the model.

- **Total Generator Output:** This is the gross power generated by the turbine.
- Air Compressor Use: The power required to operate the air compressor.
- **Turbine Shaft Losses:** This variable accounts for any turbine electricity losses that are not incorporated into the lossed due to air compressor use.
- **Gross Plant Output:** This is the net power generated by the turbine. This is the gross output of the turbine minus the power required by the air compressor and any miscellaneous losses.
- **Misc. Power Block Use:** This is the electrical power required to operate pumps and motors associated with the power block area.
- Air Separation Unit Use: This is the power utilization of the compressors in the air separation system.
- Gasifier Use: This is the power utilization of the gasification system.
- **Sulfur Capture Use:** This is the power utilization of the sulfur capture system (this does not include the claus or beavon stretford systems).
- **Claus Plant Use:** This is the power utilization of the claus plant equipment.
- **Beavon Stretford Use:** This is the power utilization of the beavon stretford system.
- Water-Gas Shift Reactor Use: This is the power-equivalent of the steam recovered from the water-gas shift reactor.
- Selexol  $CO_2$  Capture Use (MW): This is the power utilization of the  $CO_2$  capture system.
- **Net Electrical Output:** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties). Also included are credits from steam generated and reused to produce electricity.

# **Overall IGCC Plant Mass In/Out Results**

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0			<u>C</u> onfigure Pla	mt 🏻		Se	et <u>P</u> ar	ame	ters		<u>G</u> et Resul	ts	
	ſ	On Pi	erall ant Fuel	<u>A</u> ir Separation	Ga A	asifier Area	<u>S</u> u Ren	lfur 10val	CO2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stack	
*			Plant l	Inputs		Flow F (tons/	late hr)		PI	ant Outputs		Flow Rate (tons/hr)	
B		1	Coal		_	197.	.6	1	Slag			18.68	
ളി		2	Oil			0.72	03	2	Ash Disposed			0.0	
		3	Natural Gas			0.0	1	3	Other Solids Dis	posed		0.0	
		4	Petroleum Coke	etroleum Coke			1	4	Particulate Emiss	ions to Air		2.620e-03	
		5	Other Fuels			6.3036	9-02	5	Captured CO2			469.7	
<u> ?</u> 1∭		6	Total Fuels			198.	.3	6	By-Product Ash	Sold		0.0	
2		7						7	By-Product Gyp:	sum Sold		0.0	
		8	Lime/Limestone			0.0		8	By-Product Sulfi	ur Sold		4.093	
		9	Sorbent			0.0		9	By-Product Sulfi	uric Acid Sold		0.0	
		10	Ammonia			0.0	·	10	Total Solids & L	iquids		492.4	
		11	Activated Carbon			0.0		11					
		12	Other Chemicals, Solv	rents & Catalys	t	4.6656	9-03	12	See Tab				
		13	Total Chemicals			4.6656	9-03	13					
		14	Oxidant			187.	.9	14					
		15	Process Water			86.7	1	15					
		Pr	ocess Type: Overal	l Plant		-	[						
			<u>1</u> . Diagram 🖌 <u>2</u>	. Plant Perf.	<u>} 3</u>	Mass In/	Out	4.0	ðas Emissions 🖌	<u>5</u> . Total Co	st <u>6</u> .Co	st Summary	

Overall IGCC Plant – Mass In/Out result screen.

#### **Plant Inputs**

**Coal:** Flow rate of coal used in the power plant.

**Oil:** Flow rate of oil used in the power plant.

Natural Gas: : Flow rate of natural gas used in the power plant

Petroleum Coke: Total mass of petroleum coke used in the power plant

- Other Fuels: Flow rate of other fuels used in the power plant
- **Total Fuels:** This is the flow rate of fuel entering the power plant. This result is highlighted in yellow.
- Lime/Limestone: Total mass of this reagent used in the power plant on a wet basis.
- Sorbent: Total mass of sorbent used in the power plant

Ammonia: Total mass of ammonia used in the power plant.

- Activated Carbon: Flow rate of activated carbon injected in the power plant.
- **Other Chemicals, Solvents & Catalyst:** Flow rate of other chemicals, solvents and catalysts used in the power plant.
- **Total Chemicals:** Flow rate of reagent entering the power plant. This result is highlighted in yellow.
- **Oxidant:** Flow rate of oxidant entering the power plant. This includes oxygen, nitrogen and argon.

**Process Water:** Flow rate of water used in the power plant.

#### **Plant Outputs**

**Slag:** Flow rate of slag from the power plant on a dry basis.

- Ash Disposed: Flow rate of ash from the power plant on a dry basis.
- **Other Solids Disposed:** Flow rate of scrubber and other treatment solid wastes from the power plant on a dry basis.
- Particulate Emissions to Air: Flow rate of particulates emitted to the air from the plant.
- **Captured CO₂:** Flow rate of the captured CO₂.
- **Byproduct Ash Sold:** : Flow rate of ash (bottom and fly ash) sold in commerce as a by-product on a dry basis.
- **Byproduct Gypsum Sold:** : Flow rate of flue gas treatment solids sold in commerce as a by-product on a dry basis.
- **Byproduct Sulfur Sold:** Flow rate of elemental sulfur recovered from flue gas and sold in commerce as a by-product on a dry basis.
- **Byproduct Sulfuric Acid Sold:** Total mass of sulfuric acid recovered from the flue gas and sold in commerce as a by-product.
- **Total Solids & Liquids:** This is the total wet solid mass exiting the power plant. This result is highlighted in yellow.

### **Overall IGCC Plant Gas Emissions Results**

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			<u>C</u> onfigure Plant	/	Set <u>P</u> a	rame	ters		<u>G</u> et Resul	ts
	ſ	Ov Pl	e <u>rall</u> F <u>u</u> el <u>A</u> ir ant F <u>u</u> el Separation	Gasifier Area	Ret	ulfur noval	CO2 Capture	Power <u>B</u> lock	B <u>y</u> -Prod. Mgmt	Stack
2 2 2			Stack Gas Component	Flor (to:	w Rate ns/hr)		Stack	Gas Component	t	Flow Rate (tons/hr)
5		1	Nitrogen (N2)	2	464	1	Total SOx (equive	alent SO2)		0.1770
<b>1</b>		2	Oxygen (O2)	4	80.9	2	Total NOx (equiv	alent NO2)		5.328e-02
11		3	Water Vapor (H2O)	4	39.1	3				
411		4	Carbon Dioxide (CO2)	4	48.62					
Ш		5	Carbon Monoxide (CO)		0.0 5	5				
111		6	Hydrochloric Acid (HCl)	0.	1126	6				
111		7	Sulfur Dioxide (SO2)	0.	1770	7				
111		8	Sulfuric Acid (equivalent SO3)		0.0	8				
Ш		9	Nitric Oxide (NO)	3.3	01e-02	9				
Ш		10	Nitrogen Dioxide (NO2)	2.6	64e-03	10				
Ш		11	Ammonia (NH3)		0.0	11				
Ш		12	Argon (Ar)	7	.635	12	Use Result Tools	under View		
Ш		13	Total Gases	3	440	13	menu for alterna	te units		
Ш		14				14				
		Pr	cess Type: Overall Plant			15				
	ľ		<u>1</u> . Diagram <u>2</u> . Plant Perf.	<u>3</u> . Mass	In/Out	<u>\ 4</u>	Gas Emissions	<u>5</u> . Total Cos	nt <u>6</u> .Co	st Summary /

Overall IGCC Plant – Gas Emissions result screen.

#### **Stack Gas Component**

Each result is described briefly below:

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCI): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

- **Total Gases:** Total of the individual components listed above. This item is highlighted in yellow.
- Total SOx (equivalent SO₂): Total mass of SO_x as equivalent SO₂.

Total NOx (equivalent NO₂): Total mass of NO_x as equivalent NO₂.

# **Overall IGCC Plant Total Cost Results**

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	Ove <u>r</u> a Plant	t F <u>u</u> el	<u>A</u> ir Separation	Gasif Are	fier <u>S</u> ulf a Remo	ur val C <u>O</u> 2 C	apture Power I	lock By-Pro Mgn	od. 1t Stac <u>k</u>
		Tecl	hnology		Fixed O&M (M\$/yr)	Variable O&M (M\$/yr)	Total O&M (M\$/yr)	Annualized Capital (M\$/yr)	Total Levelized Annual Cost (M\$/yr)
	1	Air Separation Unit			6.399	20.86	27.26	28.07	55.33
111	2	Gasifier Area			14.32	42.45	56.77	50.61	107.4
	3	Particulate Control			0.0	0.0	0.0	0.0	0.0
	4	Sulfur Control			3.809	1.181	4.990	9.526	14.52
	5 Mercury Control			0.0	0.0	0.0	0.0	0.0	
	6	CO2 Capture		6	6.820	31.71	38.53	25.15	63.68
	7	Power Block	ock		7.147	-34.37	-27.22	52.61	25.38
	8	Post-Combustion N	lOx Control		0.0	0.0	0.0	0.0	0.0
Ш	9	Subtotal			38.50	61.84	100.3	166.0	266.3
Ш	10	Emission Taxes			0.0	0.0	0.0	0.0	0.0
Ш	11	Total			38.50	61.84	100.3	166.0	266.3
Ш	12								
Ш	13								
Ш	14								
	Proce	ss Type: Overall	Plant		<b>*</b>	Costs	are in Constant	2005 dollars.	
	<u>1</u> .	Diagram 🖌 <u>2</u> .	Plant Perf.	<u>3</u> . M	ass In/Out 🖌	4. Gas Emiss	sions <u>5</u> . To	talCost	<u>6</u> . Cost Summary /

Overall IGCC Plant – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs associated with the power plant as a whole. Each technology (row) is described briefly below.

#### Technology

- **Air Separation Unit:** This is the capital cost for the Air Separation process area of the plant.
- **Gasifier Area:** This is the capital cost for the equipment in the gasifier process area of the plant.
- **Particulate Control:** This is the capital cost for the equipment that performs particulate capture in the plant.
- **Sulfur Control:** This is the capital cost for the equipment that performs sulfur capture in the plant.
- **Mercury Control:** This is the capital cost for the mercury process area of the plant.
- **CO₂ Capture:** This is the capital cost for the equipment that performs CO₂ capture in the plant.
- **Power Block:** This is the capital cost for the power block process area of the plant.
- **Post-Combustion NO_x Control:** This is the capital cost for the equipment that captures post-combustion  $NO_x$  in the plant.
- **Subtotal:** This is the cost of the conventional and advanced abatement technology modules alone. This is the total abatement cost. The subtotal is highlighted in yellow.
- **Emission Taxes:** This is the sum of the user assessed taxes on the plant emissions of  $SO_2$ ,  $NO_x$  and  $CO_2$ .
- **Total:** This is the total cost of the entire power plant. This result is highlighted in yellow.
- Each cost category (column) is described briefly below.
  - **Fixed O&M:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs for each technology.
  - **Variable O&M:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs associated with a technology.
  - **Total O&M:** This is the sum of the annual fixed and variable operating and maintenance costs for each technology.
  - **Annualized Capital:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
  - **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow

# **Overall IGCC Plant Cost Summary Results**

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6		<u>C</u>	onf	figure Pla	nt	Se	t <u>P</u> aramete	rs	-	<u>G</u> et Results	
	Γ	Dve <u>r</u> all Plant	Ĩ	F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac <u>k</u>
					Technology	r	Capital Required (M\$)	Capital Required (\$/kW-net)	Revenue Required (M\$/yr)	Revenue Required (\$/MWh)	
			1	Air Separati	on Unit		189.7	385.3	55.33	17.10	
8			2	Gasifier Are	a		342.0	694.8	107.4	33.18	
⊨∭		3 Particulate Control 4 Sulfur Control 5 Mercury Control 6 COO Control					64.36	130.8	14.52	0.0	
							04.50	0.0	0.0	0.0	
<u></u>			6	CO2 Captur	e		169.9	345.2	63.68	19.68	
8			7	Power Block	<u>،</u>		355.5	722.2	25.38	7.845	
<u> </u>			8	Post-Combu	stion NOx Cor	itrol	0.0	0.0	0.0	0.0	
			9	Subtotal			1121	2278	266.3	82.29	
			10	Emission Ta	ixes		0.0	0.0	0.0	0.0	
			11	Total			1121	2278	266.3	82.29	
			12								
			13								
			14								
	F	Process T	ype	0verall	Plant Plant Perf	Z Mase Inf	Out / 4 Ge	Costs are in	Constant 2005 (	dollars.	Summarz
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Overall IGCC Plant – Cost Summary result screen.

#### Technology

- **Air Separation Unit:** This is the capital cost for the Air Separation process area of the plant.
- **Gasifier Area:** This is the capital cost for the gasifier process area of the plant.
- **Particulate Control:** This is the capital cost for the equipment that captures particulates in the plant.
- **Sulfur Control:** This is the capital cost for the equipment that captures sulfur in the plant.
- **Mercury Control:** This is the capital cost for the mercury process area of the plant.
- $CO_2$  Capture: This is the capital cost for the equipment that captures  $CO_2$  in the plant.
- **Power Block:** This is the capital cost for the power block process area of the plant.
- **Post-Combustion NO_x Control:** This is the capital cost for the postcombustion equipment that captures  $NO_x$  in the plant.
- **Total:** This is the sum of the capital costs for all the process areas in the plant.

Each cost category (column) is described briefly below.

**Capital Cost:** The total capital requirement (TCR). This is the money that is placed (capitalized) on the books of the utility on the service date. The total cost includes the total plant investment plus capitalized plant

startup. Escalation and allowance for funds used during construction (AFUDC) are also included. The capital cost is given on both a total and an annualized basis.

**Revenue Required:** Amount of money that must be collected from customers to compensate a utility for all expenditures in capital, goods, and services. The revenue requirement is equal to the carrying charges plus expenses. The revenue required is given on both an annualized and a net power output basis.

# Fuel

The screens associated with the **Fuel Technology** Navigation Tab display and define the composition and cost of the fuels used in the plant. The IECM supports the use of various fuels, ranging from coals of various rank, fuel oil of various weight, and natural gas of various places of origin. Default properties of fuels are provided, but user-specified properties can also be easily substituted.

The combustion model currently supports the use of pulverized coal in the furnace, with natural gas available as a reburn option to the in-furnace NOx controls and an optional natural gas auxiliary boiler. The coal properties can be modified. The natural gas properties will be made available in the future. At present, a common Pennsylvania natural gas is assumed (NGCC).

The natural gas combined cycle (NGCC) plant configurations all assume natural gas for fuel. The properties can be specified by the user.

The integrated gasification combined cycle (IGCC) plant configurations assume coal gasification to produce a synthetic fuel gas. The coal properties must be chosen from a predetermined set of coals.

### **Fuel Properties Coal Input**

The selection of the particular coal model default, cleaned, saved externally, or userspecified and its ultimate and ash properties are selected and editable on the **Properties** input screen.

Untitled	)*							
	<u>C</u> onfigure Pl	ant	Set Par	amete	rs	<u>G</u> e	t Results	
Ove <u>r</u> all Plant	Fuel	Base Plant C	Emission Constr <u>a</u> int Mercury	<u>N</u> C Cont	)x <u>T</u> SP trol Control	<u>S</u> O2 Control	C <u>O</u> 2 Capture	By-Prod. Mgmt
Cur	rent Fuel ——			Fue	l Databases —			
Nam	e: Default			Fuel	Appalachia	n Low Sulfur		-
Ran	k: Bituminous			Ran	k: Bituminous			
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	Property	Value	Save For All		Property	Value	Databas	e
1	Heating Value	10900	Plant Types	1	Heating Value	1.308e+04	New	
2	Carbon	61.2	Fuel Types	2	Carbon	71.74	Databas	e
3	Hydrogen	4.2	1 ruer rypes	3	Hydrogen	4.620		
4	Oxygen	6.02	Save In	4	Oxygen	6.090	Use	
5	Chlorine	0.17	Database	5	Chlorine	7.000e-02	This Fue	d
6	Sulfur	3.25		6	Sulfur	0.6400		
7	Nitrogen	1.16	Use Default	7	Nitrogen	1.420	Delete	
8	Ash	11.0	Ash Properties	8	Ash	9.790	This Fue	
9	Moisture	13.0		9	Moisture	5.630		
10	Cost	27.7	Edit Ash	10	Plant Type	<any></any>	View Ash	1
11			Properties	11	Fuel Type	Coal	Propertie	S

Fuel – Properties input screen.

There are two panes on the Fuel Properties input screen: one for the composition, higher heating value, and cost of the **Current Fuel**, the other for properties of the fuels in the **Fuel Databases**. The **Current Fuel** is the fuel for which the model will conduct its calculations. The IECM interface currently supports only one fuel selection per session. The **Fuel Databases** pane displays the properties for other selectable fuels. From this screen, you may choose a fuel from the model defaults, enter a user-defined fuel, or choose a previously saved user-defined fuel. Properties of existing fuels may be modified and new fuels may be created and saved to user specified databases. The user-specified databases can be transferred from one user to another. A full suite of buttons have been provided to make the selection and management of the fuel properties easier.

Both the **Current Fuel** pane and the **Fuel Databases** pane display the following information: for a fuel.

- **Name:** This is the name of the fuel, it may be the trade name or a unique identifier supplied by the user.
- **Rank:** The rank of a coal refers to the degree of coalification endured by the organic matter. It is estimated by measuring the moisture content, specific energy, reflectance of vitrinite or volatile matter (these are known as rank parameters
- **Source:** The model provides the values for default fuel properties, these can be used "as is" or modified and used. Modified fuels maybe stored in a new database or an existing database. Source displays the database file from which the data was retrieved, or indicates that the data has been enetered by the user.
- **Fuel Properties:** The property value spreadsheet is used to display the heating value and content of carbon, hydrogen, oxygen, chlorine, sulfur, nitrogen, ash, and moisture are specified on a weight percent basis for coal fuels. The data can be edited only in the **Current Coal** pane. The fuel composition is used in a combustion equation to calculate the flue gas composition in the furnace. The heating value is

used to calculate the mass flow rate of fuel. Property data also determines the fuel rank (bituminous, subbituminous, or lignite). This, in turn, determines the default values of several boiler parameters. The editable fuel properties are:

- **Heating Value:** This is the higher heating value of the fuel in Btu/lb.
- **Carbon:** The weight percent of carbon in the fuel on a wet basis.
- **Hydrogen:** This is the weight percent of hydrogen in the fuel on a wet basis.
- **Oxygen:** This is the weight percent of oxygen in the fuel on a wet basis.
- **Chlorine:** This is the weight percent of chlorine in the fuel on a wet basis.
- **Sulfur:** This is the weight percent of sulfur in the fuel on a wet basis.
- **Nitrogen:** This is the weight percent of nitrogen in the fuel on a wet basis.
- **Ash:** This is the weight percent of ash in the fuel on a wet basis.
- **Moisture:** This is the weight percent of moisture in the fuel on a wet basis.
- **Cost:** This is the total as-delivered cost of the coal on a wet basis. A default value is provided for the default coals provided in the model. This value can be updated on this input screen or the fuel cost screen.
- Ash Properties: The property value spreadsheet is also used to display the oxide content of the ash in coal on a percent of total ash basis. The data can be edited only in the **Current Fuel** pane. The ash content is used to determine the resistivity of the ash. This, in turn, determines the specific collection area (SCA) of the cold-side ESP. The editable ash properties are:
  - **SiO**₂: The percent by weight of silicon dioxide in the ash.
  - Al₂O₃: The percent by weight of Aluminum Oxide in the ash.
  - **Fe₂O₃:** The percent by weight of ferric oxide in the ash.
  - **CaO:** The percent by weight of calcium oxide in the ash.
  - **MgO:** The percent by weight of magnesium oxide in the ash.
  - **Na₂O:** The percent by weight of sodium oxide in the ash.
  - **K**₂**O**: The percent by weight of potassium oxide in the ash.
  - **TiO₂:** The percent by weight of titanium dioxide in the ash.
  - **MnO₂:** The percent by weight of manganese dioxide in the ash.
  - $P_2O_5$ : The percent by weight of phosphorus pentoxide in the ash.
  - **SO**₃: The percent by weight of sulfur trioxide in the ash.

The **Current Fuel** pane displays two check boxes that are grayed out when the "model_default_fuels.mdb" database file is currently open. If a personal fuel

database is opened, these two check boxes become active. The check boxes serve to allow the fuel to be available to multiple plant types or fuel types. The current fuel must be saved to make the restrictions permanent. Once saved, all new sessions will use these filters to determine which fuels will be listed in the **Fuel** menu. These check boxes are:

- **Plant Types:** This is a filtering agent that specifies whether or not this fuel is restricted to the current plant type. If the box is not checked, the fuel will only be available to new sessions with the same plant type as the current session. If the box is checked, the fuel will be available to all new sessions, regardless of their plant type.
- **Fuel Types:** This is a filtering agent that specifies whether or not this fuel is restricted to a particular fuel type. If the box is not checked, the fuel will only be available to new sessions that use the same primary fuel type as the current session. If the box is checked, the fuel will be available to all new sessions, regardless of the primary fuel type they use. This filter will be more important when oil fuels are made available in the IECM.

The **Fuel Databases** pane displays two additional items that verify whether or not a particular fuel is restricted to particular plant types or for primary fuel types. Either a particular plant type and fuel type will be specified or the word "<All>" will be displayed.

### **Selecting a Fuel**

The **Current Fuel** pane displays the fuel that is in use by the model. The **Fuel Databases** pane initially displays the first default fuel in the model's default database. To make the fuel that is displayed in the **Fuel Database** pane the fuel to be used by the model, press the **Use this Fuel** button. The fuel will then be displayed in the **Current Fuel** pane. To view the ash properties, press the **View Ash Properties** button in the **Fuels Database**, the ash properties are displayed and the button that was pressed, labeled **View Ash Properties** has changed to **View Fuel Properties**. This button toggles between **View Ash Properties** and **View Fuel Properties**. To find other fuels:

- Select a Different Fuel in the Open Database: Select the pull down menu on the text box labeled **Fuel:**. The list of fuels in the database is displayed another fuel can be chosen.
- Select a Different Open Database: Select the pull down menu on the text box labeled Source: The list of other open databases is displayed.
- Open Another Fuel Database: When pressed the button labeled Open Database will display the Windows Open screen. All files with .fdb extension will be displayed. .fdb is the default extension for the Fuel Databases files. Select a file and press the Open button.

### **Modifying a Fuel**

The fuel values that are displayed in the **Current Fuel** pane may be modified. Put the cursor into the cell containing the value of the property to be edited and enter the new value. To edit the ash properties of the current fuel; press the **Edit Ash Properties** button in the **Current Fuel** pane, the ash properties are displayed and the button that was pressed, labeled **Edit Ash Properties** has changed to **Edit Fuel Properties.** This button toggles between **Edit Ash Properties** and **Edit Fuel Properties.** The ash properties may be edited in the same way as the fuel properties. Place the cursor in the value of the property to be modified and enter the new value. The model will run using the fuel that is displayed in the **Current Fuel** pane.

#### Saving a Modified Fuel

A fuel that has been modified may be saved to any user specified fuel database except the default database, **model_default_fuels.mdb**. Use the **Save in Database** button to save the modified fuel, displayed in the **Current Fuel** pane to the database that is displayed in the **Source** text box. If the default database, **model_default_fuels.mdb** is displayed in the text box titled **Source**, the **Save in Database** button will be grayed out, not active. Activate the **Save in Database**, by opening another database or creating a new database.

### **Deleting a Fuel**

A fuel that is displayed in the **Fuel Databases** pane, may be deleted using the **Delete this Fuel** button, if it is not a model default fuel. Fuels in the model default database, **model_default_fuels.mdb**, cannot be deleted.

### **Open Database**

Press the **Open Database** button on the **Fuels Database** pane and the **Windows Open Screen** will appear. A valid fuel database file as an .fdb extension. Click on the database file to open and press the **Open** button. The **Fuels Database** displays the first fuel in the selected database and the **Source**: text box displays the full path and file name of the database that has just been opened.

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	Open as read-only	

Fuels – Windows Open screen.

#### **New Database**

Press the **New Database** button on the **Fuels Database** pane and the **Windows Save As Screen** will appear. Type in the name of the new database file into the **File name:** text box. All fuel database files have an **.fdb** extension. Press the **Save** button. The **Source**: text box displays the full path and file name of the new database and all other fuel values in the **Fuels Database** pane will be blank

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Fuels – Windows Save As screen.

# **Fuel Mercury Input**

The concentration of mercury in the as-fired coal and speciation of mercury after combustion are entered on the **Mercury** input screen

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Å		1	Concentrations on a Dry Basis								
		2	Mercury in Coal (elemental)	ppmw		0.1200		0.0	2.000	calc	
ß		3	Mercury in Oil (elemental)	ppmw		3.300e-03	<u></u>	0.0	0.1000	calc	
1		4	Mercury in Natural Gas (elemental)	ppmw		0.0		0.0	1.000e-02	caic	
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<u>.</u>		8	Oxidized	%		70.00	<b>N</b>	0.0	100.0	calc	
		9	Particulate	%		0.0		0.0	100.0	calc	
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Fuel – Mercury input screen.

Each parameter is described briefly below:

### **Concentration on a Dry Basis**

Trace elements found in fuels are typically measured and reported as a mass concentration given on a dry basis. The IECM uses this concentration in conjunction with the fuel flow rate and fuel moisture to determine the mass flow rate. Currently Mercury is the only trace species tracked in the IECM.

**Mercury in Coal (elemental):** This input parameter specifies the mass concentration of total mercury in the coal given on a dry basis. The mercury concentration should be given on an elemental basis, not on a mercury compound basis. The default value is a function of the coal rank.

- **Mercury in Oil (elemental):** This input parameter specifies the mass concentration of total mercury in the oil. The mercury concentration should be given on an elemental basis, not on a mercury compound basis.
- **Mercury in Natural Gas (elemental):** This input parameter specifies the mass concentration of total mercury in the natural gas. The mercury concentration should be given on an elemental basis, not on a mercury compound basis.

#### **Mercury Speciation**

Once the fuel is combusted, the mercury can be identified in primarily two chemical states: elemental  $(Hg^0)$  and oxidized  $(Hg^{+2})$ . Although mercury can alternatively be reported as particulate or gas phase, the IECM assumes Mercury is reported on an elemental and oxidized basis.

- **Elemental:** This is the percent of total mercury that is in an elemental state  $(Hg^0)$  after combustion. Elemental mercury is typically unreactive and passes through a power plant. The default value is a function of the coal rank.
- **Oxidized:** This is the percent of total mercury that is in an oxidized state  $(Hg^{+2})$  after combustion. Oxidized mercury is very reactive and typically forms mercury compounds. The default value is a function of the coal rank.
- **Particulate:** This parameter is not currently used in the IECM. It's value is set to force the sum of the speciation types to be 100%.

# **Fuel Cost Input**

The cost of the cleaned coal, transportation costs, and other miscellaneous for coal and the auxiliary natural gas costs are accessed on the **Cost** input screen. Note that coal parameters are not displayed for the **Combustion (Turbine)** plant type.

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Fuel-Cost input screen.

Each parameter is described briefly below.

### **Coal Costs**

Coal is the primary fuel for the combustion plant type. The costs associated with the coal have been simplified and contain only the total as-fired cost.

- **Total Delivered Cost (as-fired):** This is the total cost of delivered coal on a wet ton basis in dollars per ton. It is assumed to contain any costs of cleaning and transportation. The total cost in units of \$/ton is the same value as shown on the fuel properties screen.
- **Total Delivered Cost (as-fired):** This is also provided in units of \$/MBtu. This value cannot be edited. It is based on the value given above in units of \$/ton.

#### Aux. Natural Gas Costs

Natural gas is an auxiliary fuel used as an option for the combustion NOx control and the amine  $CO_2$  capture configurations.

**Natural Gas Cost:** This is also provided in units of \$/MBtu. This value cannot be edited. It is based on the value given in units of \$/mscf.

**Natural Gas Cost:** This is also provided in units of \$/MBtu. This value cannot be edited.

# **Fuel Aux. Gas Properties Input**

The natural gas composition and density can be entered on the natural gas properties screen. The screen below is shown when accessed from the **Combustion** (**Turbine**) plant type. It is also available for combustion plant configurations that include **CO₂ Capture** with an Auxiliary Natural Gas Boiler or In-Furnace **NO**_x

**Control** with Gas Reburn and is accessed by selecting 4. Aux. Gas from the Fuel Screen of the Set Parameters Tab

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1		2	Natural Methene (CH	Gas Compositi A	201	wo1%		83.40		0.0	100.0	83.40	
1		4	Ethane (C2H6			vo1%	_	15.80		0.0	100.0	15.80	
		5	Propane (C3H	, 18)		vol %		0.0		0.0	100.0	0.0	
		6	Carbon Dioxi	de (CO2)		vol %		0.0		0.0	100.0	0.0	
		7	Oxygen (O2)			vol %		0.0		0.0	100.0	0.0	
41		8	Nitrogen (N2)	)		vol %		0.8000		0.0	100.0	0.8000	
_		9	Hydrogen Su	lfide (H2S)		vol%		0.0		0.0	100.0	0.0	
4		10	Matural Care F			11. ( A		4.940 - 02	7	0.0	1000	aala	
		11	Natural Gas L	Jensity		16/CU R	_	4.0496-02		0.0	1000	calc	
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Fuel – Auxiliary Natural Gas input screen.

The **Natural Gas** input screen displays and allows the user to update the fuel properties of Natural Gas.

**Higher Heating Value:** Higher heating value (HHV) is the thermal energy produced in Btu/lb of fuel from completely burning the fuel to produce carbon dioxide and liquid water. The latent heat of condensation is included in the value. This value is calculated from the natural gas composition below and cannot be changed by the user.

#### **Natural Gas Composition**

- Methane (CH4): The volume, by percent, of methane in the natural gas.
- Ethane (C2H6): The volume, by percent, of ethane in the natural gas.
- Propane (C3H8): The volume, by percent, of propane in the natural gas.
- **Carbon Dioxide (CO2):**The volume, by percent, of carbon dioxide in the natural gas.
- **Oxygen (O2):**The volume, by percent, of oxygen in the natural gas.
- Nitrogen (N2): The volume, by percent, of nitrogen in the natural gas.
- **Hydrogen Sulfide (H2S):** The volume, by percent, of hydrogen sulfide in the natural gas.
- **Natural Gas Density:** The natural gas density is a weighted average of the individual densities of the natural gas constituents. This value is used in many unit conversion operations.

# **Fuel Coal Diagram**

The **Fuel** Technology Navigation Tab in the **<u>Get Results</u>** program area contains the **Diagram** result screen. It displays the properties set up in the Fuel Properties input screens of the of the <u>**Set Parameters**</u> program area.

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		Coal Flow Rate (ton/hr) Rank Heating Value (Btu/lb) Carbon (wt %) Hydrogen (wt %) Oxygen (wt %) Chlorine (wt %) Sulfur (wt %) Nitrogen (wt %) Ash (wt %) Process Type: Coal 1. Diagram	166.7 Bituminous 1.326e+04 73.81 4.880 5.410 6.000e-02 2.130 1.420 7.240 5.050 Properties		<u> </u>	Tr Mercury (lb/l	<u>ace Element Flows</u> ar) 3.71	99e-02

Fuel — Diagram result screen for coal.

The **Coal Diagram** result screen displays fuel composition and flow rate information, which is described briefly below.

- **Coal Flow Rate:** Coal flow rate into the boiler on a wet basis. Waste products removed prior to the burners are not considered here.
- **Rank:** The rank of the coal based on the higher heating value. This is primarily determined by the higher heating value and to a lesser degree by the sulfur and ash content.
- **Heating Value:** Higher heating value (HHV) is the thermal energy produced in Btu/lb of fuel (wet) from completely burning the fuel to produce carbon dioxide and liquid water. The latent heat of condensation is included in the value.
- **Carbon:** The carbon content of the coal by weight on an elemental and wet basis.
- **Hydrogen:** The hydrogen content of the coal by weight on an elemental (H) and wet basis.
- **Oxygen:** The oxygen content of the coal by weight on an elemental (O) and wet basis.
- **Chlorine:** The chlorine content of the coal by weight on an elemental (Cl) and wet basis.
- **Sulfur:** The sulfur content of the coal by weight on an elemental (S) and wet basis.

**Nitrogen**: The nitrogen content of the coal by weight on an elemental (N) and wet basis.

**Ash:** The ash content of the coal by weight on a wet basis.

Moisture: The inherent moisture content of the coal by weight.

#### **Trace Element Flows**

Trace elements are now supported in the IECM. The mass flow rate is reported in units of pounds per unit of time. All values reflect the elemental mass flow rate.

**Mercury:** This is the elemental mercury flow rate in coal. At present, mercury is not tracked in the IGCC plant type and is displayed as a zero value.

# **Fuel Natural Gas Diagram**

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	Overall Plant Fuel Power Block	NOx Control CO2 Capture By-Prod. Mgmt	Stac <u>k</u>	
	Gas Flow Rate (ton/hr) 74.37			
	Heating Value (Btu/lb) 2.276e+04   Methane (CH4) (vol %) 83.40   Ethane (C2H6) (vol %) 15.80   Propane (C3H8) (vol %) 0.0   Carbon Dioxide (CO2) (vol 0.0   Oxygen (O2) (vol %) 0.0			
	Nitrogen (N2) (vol %) 0.8000   Hydrogen Sulfide (H2S) 0.0			
	Process Type: Natural Gas Proper	rties		

Fuel – Diagram result screen for natural gas.

The **Natural Gas Diagram** result screen displays fuel composition and flow rate information, which is described briefly below.

Gas Flow Rate: The natural gas flow rate to the turbine.

**Heating Value:** Higher heating value (HHV) is the thermal energy produced in Btu/lb of fuel.

Methane (CH₄): The volume, by percent, of methane in the natural gas.

**Ethane (C₂H₆):** The volume, by percent, of ethane in the natural gas.

**Propane (C₃H₈):** The volume, by percent, of propane in the natural gas.

**Carbon Dioxide (CO₂):** The volume, by percent, of carbon dioxide in the natural gas.

**Oxygen (O₂):** The volume, by percent, of oxygen in the natural gas.

Nitrogen (N₂): The volume, by percent, of nitrogen in the natural gas.

 $\label{eq:Hydrogen Sulfide (H_2S):} The volume, by percent, of hydrogen sulfide in the natural gas.$ 

# **Air Separation**

This chapter illustrates the configuration, inputs and results of the air separation technology. It is presently used only for the IGCC plant configurations.

# **Air Separation Performance Inputs**

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511		1	Oxidant Composition								
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3		3	Argon (Ar)	vo1%		4.234		0.0	100.0	Calc	
		4	Nitrogen (N2)	vo1%		0.7657	M	0.0	100.0	Calc	
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•		6	Final Oxidant Pressure	psia		580.0	1	0.0	800.0	calc	
		7	Morimum Train Conosity	th motor/hr		1 125 04		626.0	1 1 250+04	1.1250+04	
21		0	Number of Operating Trains	integer		1.1556-04		Menu	Menu	Calc	
7		10	Number of Spare Trains	integer	-	0 -		Menu	Menu	0	
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		12	Unit ASU Power Requirement	kWh/ton CO2		210.4	V	0.0	550.0	calc	
		13	Total ASU Power Requirement	% MWg		8.375	V	0.0	40.00	calc	
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Air Separation – Performance input screen.

#### **Oxidant Composition**

- **Oxygen (O₂):** This is the percent of oxygen that is in the oxidant that is produced by the air separation unit. The value is fixed for the IGCC plant type.
- **Argon (Ar):** This is the percent of argon that is in the oxidant that is produced by the air separation unit.
- **Nitrogen (N₂):** This is the percent of nitrogen that is in the oxidant that is produced by the air separation unit.

- **Final Oxidant Pressure:** The final oxidant stream from the ASU can be provided at a high pressure. The default value is determined by the plant type being used.
- **Maximum Train Capacity:** The maximum production rate of oxidant is specified here. It is used to determine the number of operating trains required.
- **Number of Operating Trains:** This is the total number of operating trains. It is used primarily to calculate capital costs. The value must be an integer
- **Number of Spare Trains:** This is the total number of spare trains. It is used primarily to calculate capital costs. The value must be an integer.
- **Unit ASU Power Requirement:** The main air compressor (MAC) pressurizes atmospheric air to approximately 550 kPA (65 psig), but is expressed as a function of the oxygen product required.
- **Total ASU Power Requirement:** This is the electricity used by the air separation unit for internal use. A majority of the power is used for the main air compressor and a secondary amount used for the product stream compressor (if required). It is expressed as a percent of the gross plant capacity.

# **Air Separation Retrofit Cost Inputs**



Air Separation – Retrofit Cost input screen.

#### **Capital Cost Process Area**

**Air Separation Unit:** The retrofit factor is a ratio of the costs of retrofitting an existing facility with an air separation unit versus a new facility, using the same equipment.

# **Air Separation Capital Cost Inputs**

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Stac <u>k</u>	By-Prod. Mgmt	Power <u>B</u> lock	e	CO2 Capture	dur oval	Gasifie <u>r</u> <u>S</u> ulf Area Remo	Plant Fuel Air Separation	)verall P <u>l</u> a		
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3.000	10.00	0.0		3.000		years	1 Construction Time	1		¥
							2	2		Ba
10.00	50.00	0.0		10.00		%PFC	3 General Facilities Capital	3		-
10.00	50.00	0.0		10.00		%PFC	4 Engineering & Home Office Fees	4		
15.00	100.0	0.0		15.00		%PFC	5 Project Contingency Cost	5		P
5.000	100.0	0.0		5.000		%PFC	6 Process Contingency Cost	6		0
0.5000	10.00	0.0		0.5000		%PFC	7 Royalty Fees	7		
							8	8		N?
							9 Pre-Production Costs	9	Ш	
1.000	12.00	0.0		1.000		months	0 Months of Fixed O&M	10	Ш	
1.000	12.00	0.0		1.000		months	1 Months of Variable O&M	11	Ш	
2.000	10.00	0.0		2.000		%TPI	12 Misc. Capital Cost	12	Ш	
							.3	13	Ш	
0.5000	10.00	0.0		0.5000		%TPC	4 Inventory Capital	14	Ш	
							15	15	Ш	
						-		16	Ш	
							17	17	Ш	
100.0	100.0	0.0		100.0		%	8 TCR Recovery Factor	18	Ш	
	) dollars.	Constant 2000	in C	Costs are in		~	ocess Type: Air Separation	Proc		
			/	O&M Cost	<u>4</u> .	3. Capital Cost	erformance 🖌 2. Retrofit Cost 🗼	<u>1</u> . Perf		
	100.0 ) dollars.	0.0 Constant 2000	in C	100.0 Costs are in O&M Cost	<u>4</u> .1	% 3. Capital Cost	18 TCR Recovery Factor vocess Type: Air Separation erformance 2. Retrofit Cost 1	17 18 Proc <u>1</u> . Perf		

Air Separation – Capital Cost input screen.

Inputs for capital costs are entered on the Capital Cost input screen.

**Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

- **General Facilities Capital (GFC):** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable

O&M costs are described below with the addition of a miscellaneous capital cost factor.

- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

# **Air Separation O&M Cost Inputs**

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6	ſ		<u>(</u>	Configure Plant	S	et <u>P</u> ara	mete	ers			<u>G</u> et Res	ults	
		Ove <u>r</u> ail	Plar	nt F <u>u</u> el <u>A</u> ir Separation	Gasifier Area	Sul Rem	fur oval	C <u>O</u> 2 Captu	ire Po	wer <u>B</u> lock	B <u>y</u> -Prod Mgmt	L Sta	c <u>k</u>
9				Title	Un	its	Unc	Value	Calc	Min	Max	Default	
*	I		1	Electricity Price (Base Plant)	\$/M	Wh		45.11	V	0.0	100.0	calc	
	I		2										
Ē.	I	_	3	Number of Operating Jobs	jobs/	shift		6.670		0.0	30.00	6.670	
	I	-	4	Number of Operating Shifts	shifts	s/day		4.750		0.0	10.00	4.750	
	I	-	5	On the Later Date				24.02		0.0	400.0	24.02	
21	I	-	6	Operating Labor Rate	\$/. 0(T	hr DC		24.82		0.0	100.0	24.82	
2	I	-	7	I otal Maintenance Cost Moint Cost Allocated to Labor	701	PC atal		2.000		0.0	10.00	2.000	
-	I	-	0	A dministrative & Support Cost	70 t % tota	11shor		30.00		0.0	100.0	30.00	
	I	-	9 10	Administrative & Support Cost	70 1014	114001		JU.UU		0.0	100.0	30.00	
	I	-	11										
	I	-	12										
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			14										
			15		1								
			16										
			17										
			18										
		P	roce	ess Type: Air Separation		-		Costs are	in Cor	stant 2000	dollars.		
		<u>1</u> . F	Perfo	ormance 🖌 2. Retrofit Cost 🖌	( <u>3</u> . Capital	Cost	4.0	D&M Cost					

Air Separation – O&M Cost input screen.

Inputs for O&M costs are entered on the **Air Separation O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant for the IGCC Model is an air separation unit, gasifier and the power block
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

# **Air Separation Diagram**



Air Separation – Diagram result screen.

The **Air Separation Diagram** result screen displays an icon for the Air Separation Unit and values for major flows in and out of it. Each result is described briefly below in flow:

- Atmospheric Air Temperature In: Temperature of the atmospheric air entering the air separation unit.
- **Atmospheric Air In:** Mass flow rate of air entering the air separation unit, based on the atmospheric air temperature and atmospheric pressure.
- **Atmospheric Air In:** Volumetric flow rate of air entering the air separation unit, based on the atmospheric air temperature and atmospheric pressure.
- **Nitrogen Out:** Mass flow rate of the nitrogen exiting the Air Separation Unit.
- **Nitrogen Out:** Volumetric flow rate of the nitrogen exiting the Air Separation Unit.
- **Temperature Out:** Temperature of the oxidant exiting the Air Separation Unit.
- **Oxidant Out:** Mass flow rate of the oxidant exiting the Air Separation Unit.
- **Oxidant Out:** Volumetric flow rate of the oxidant exiting the Air Separation Unit.

# **Air Separation Gas Flow Results**

		Configure Plant	Set <u>P</u> ara	meters		<u>G</u> et R	esults
Ove;	rall Pl	ant F <u>u</u> el <u>Air</u> Ga Separation A	sifier <u>S</u> ulf rea Remo	ur wal CO2 Ca	pture Power B	lock By-Pr Mg	nd. Stac <u>k</u>
		Major Gas Components	Air In (B-moles/hr)	Nitrogen Out (b-moles/hr)	Oxidant Out (B-moles/hr)	Air In (tons/hr)	Nitrogen Out (tons/hr)
	1	Nitrogen (N2)	3.878e+04	3.870e+04	83.85	543.1	541.9
	2	Oxygen (O2)	1.040e+04	0.0	1.040e+04	166.5	0.0
	3	Water Vapor (H2O)	0.0	0.0	0.0	0.0	0.0
	4 (	Carbon Dioxide (CO2)	0.0	0.0	0.0	0.0	0.0
	5 (	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0
	<b>6</b> I	Hydrochloric Acid (HCl)	0.0	0.0	0.0	0.0	0.0
	7 8	Sulfur Dioxide (SO2)	0.0	0.0	0.0	0.0	0.0
	8	Sulfuric Acid (equivalent SO3)	0.0	0.0	0.0	0.0	0.0
	9 1	Nitric Oxide (NO)	0.0	0.0	0.0	0.0	0.0
	10	Nitrogen Dioxide (NO2)	0.0	0.0	0.0	0.0	0.0
	11 4	Ammonia (NH3)	0.0	0.0	0.0	0.0	0.0
	12	Argon (Ar)	463.7	3.052e-05	463.7	9.262	6.096e-07
	13	Fotal	4.965e+04	3.870e+04	1.095e+04	718.8	541.9
	14						
	15						
	<b>▲</b>						•

Air Separation – Gas Flow result screen.

Each result is described briefly below.

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCI): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **Air Separation Capital Cost Results**

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Ľ			<u> </u>	oningure	: Plant		26	a <u>P</u> ar	ame	lers		Get Kest	uts
	C	Dvei	all Plant	F <u>u</u> e	1 <u>A</u> ir Separation	n Ge	asifie <u>r</u> Area	<u>S</u> u Rem	lfur 10val	CO2 Capture	Power <u>B</u> lock	By-Prod. <u>M</u> gmt	Stack
			Ai	r Separati	on Process Area	Costs	Capital (M\$	Cost )		Air Sepa	ration Plant Cos	sts	Capital Cost (M\$)
l		1	AirSe	paration U	Jnit		38.8	5	1	Process Facilities	Capital		38.85
I		2							2	General Facilities	Capital		3.885
l		3							3	Eng. & Home Off	ice Fees		3.885
l		4							4	Project Continge	ncy Cost		5.828
I		5							5	Process Conting	ency Cost		1.943
l		6							6	Interest Charges	(AFUDC)		5.795
I		7							7	Royalty Fees			0.1943
l		8							8	Preproduction (S	tartup) Cost		2.798
I		9							9	Inventory (Work	ing) Capital		0.2720
l		10	1						10	Total Capital Rec	uirement (TCR)		63.45
I		11	Proce	ss Facilitie	s Capital		38.8	5	11				
I		12	1						12				
I	Π	13						_	13				
I	Π	14						_	14				
I		15						_	15	Effective TCR			63.45
I		Р	mence T	mer at	- C - u			1		Costs are in t	Conctant 2000 d	allow	

Air Separation Capital Cost results screen.

The **Air Separation Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

#### Air Separation Process Area Costs

- Air Separation Unit: The cost of oxygen plants depends mostly on the oxygen feed rate to the gasifier, because size and cost of compressors and air separation systems are proportional to this flow rate. The number of trains is determined based on the total mass flow rate of oxygen. The minimum number of operating trains is two
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales

taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

#### **Air Separation Plant Costs**

- Process Facilities Capital: (see definition above)
- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

# **Air Separation O&M Cost Results**

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	Γ		<u>C</u> onfi	gure Pla	ant		Se	t <u>P</u> ar	ame	ters		<u>G</u> et Resu	lts
		Overa	11 P <u>1</u> ant	F <u>u</u> el	<u>A</u> ir Separation	Ga A	sifie <u>r</u> .rea	<u>S</u> u Rem	lfur 10val	CO2 Capture	Power <u>B</u> lock	By-Prod. <u>M</u> gmt	Stac <u>k</u>
			Va	riable Cos	st Component		O&M ( (M\$/y	Cost T)		Fixed	Cost Componen	t	O&M Cest (M\$/yr)
B		1	Electricity				15.7	6	1	Operating Labor			1.659
- - -	Ш	2	Total Varial	ole Costs			15.7	6	2	Maintenance La	bor		0.4351
		3						_	3	Maintenance M	aterial		0.6527
2		4						_	4	Admin. & Suppo	ort Labor		0.6282
N?		5						_	5	Total Fixed Cost	s		3.375
		6						_	6				
		7						_	7				
		8						_	8				
		9						_	9				
		10						_	10				
		11						_	11				
		12						_	12				
		13						_	13				
		14						_	14				
		15						_	15	Total O&M Cos	ts		19.14
		Pro	cess Type:	Air Se	paration		Y			Costs are in	Constant 2000	dollars.	
			<u>1</u> . Diagram		<u>2</u> . Gas Flow	<u></u>	Capital C	ost	4	. O&M Cost	<u>5</u> . Total Co	st /	

Air Separation – O&M Cost results screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

#### Variable Cost Component

**Electricity:** The cost of electricity consumed by the Air Separation System.

**Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

#### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

# **Air Separation Total Cost Results**

EL	M Interface	Liele							
Ē	ut view <u>window</u>	<u>T</u> eih							
	<u>C</u> onfig	gure	Plant	Se	t <u>P</u> arame	ters	Ĩ	<u>G</u> et Re	sults
	Overall Plant	F <u>u</u> el	<u>A</u> ir Separation	Gasifie <u>r</u> Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Cap	oture Power	Block By-Pro	d. t Stac <u>k</u>
			Cost (	Component		M\$/yr	\$/MWh	Percent Total	
1		1	Annual Fixed Cost			3.375	2.291	11.83	
1		2	Annual Variable Co	st		15.76	10.70	55.25	
II		3	Total Annual O&M	I Cost		19.14	12.99	67.08	
II		4	Annualized Capital	Cost		9.390	6.374	32.92	
II		5	Total Levelized An	nualCost		28.53	19.36	100.0	
II		6							
		7							
		0							
		10							
		11							
II		12							
II		13							
II		14							
II		15							
	Process Type:	Air	Separation	<b>_</b>		Costs a	re in Constan	t 2000 dollars.	
1	<u>1</u> . Diagram	6	2. Gas Flow	<u>3</u> . Capital C	ost 4	O&M Cos	t 🔥 <u>5</u> . To	otal Cost	

Air Separation – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Air Separation Unit**. Each result is described briefly below.

#### **Cost Component**

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# **Base Plant**

The **Base Plant** Technology Navigation Tab screens display and define the performance and costs directly associated with the combustion power plant, particularly the boiler. Pre-combustion and post-combustion control technologies are not considered part of the Base Plant.

The screens described in this chapter all apply to the **Combustion (Boiler)** plant type.

# **Base Plant Performance Inputs**

Inputs for the major flow rates and concentrations of the gas and solids streams are entered on the **Performance** input screen

<u>C</u> onfigure Plant	Set <u>P</u> ar	amet	ers	Ĩ		Get Res	ults
Ove <u>r</u> all Plant Fuel <u>Base Plant</u> <u>M</u> e	rcury <u>N</u> Ox Control	Cor	SP <u>S</u> O itrol Cor	D2 itro1	C <u>O</u> 2 Captur	e B <u>y</u> -Pr Mgi	od. nt Si
Title	Units	Unc	Value	Calc	Min	Max	Default
1 Gross Electrical Output	MWg		500.0	M	100.0	2500	calc
2 Unit Type			Sub-Criti 🔻		Menu	Menu	Bub-Critica
3 Steam Cycle Heat Rate, HHV	Btu/kWh		7880	M	6000	1.100e+04	calc
4 Boiler Firing Type			Tangenti 🔻		Menu	Menu	Tangential
5 Boiler Efficiency	%		89.16	M	50.00	100.0	calc
6 Excess Air For Furnace	% stoich.		20.00	M	0.0	40.00	calc
7 Leakage Air at Preheater	% stoich.		19.00	M	0.0	60.00	calc
8 Gas Temp. Exiting Economizer	°F		700.0		250.0	1200	700.0
9 Gas Temp. Exiting Air Preheater	°F		300.0		150.0	500.0	300.0
10 Percent Water in Bottom Ash Slui	ce %		0.0	M	0.0	99.99	calc
11							
12 Base Plant Power Requirements							
13 Coal Pulverizer	% MWg		0.6000	V	0.0	3.000	calc
14 Steam Cycle Pumps	% MWg		0.6500		0.0	3.000	0.6500
15 Forced Draft Fans	% MWg		1.500		0.0	5.000	1.500
16 Cooling System	% MWg		1.800		0.0	3.000	1.800
17 Miscellaneous	% MWg		1.300		0.0	5.000	1.300
18							
Process Type: Base Plant							

Base Plant—Performance input screen.

The first six inputs are highlighted in blue. Each parameter is described briefly below.

**Gross Electrical Output:** This is the gross output of the generator in megawatts (MWg). The value does not include auxiliary power
requirements. The model uses this information to calculate key mass flow rates.

- **Unit Type:** This is the type of steam turbine system being used. The possible selections are: Sub-Critical, Super-Critical, and Ultra-Supercritical. This selection determines the steam cycle heat rate default value.
- **Steam Cycle Heat Rate:** This is the gross amount of energy in steam needed to produce a kilowatt-hour (kWh) of electricity at the generator. This variable does not consider auxiliary power requirements. This heat rate, plus the boiler efficiency, is used to figure out the overall plant performance (i.e., the gross cycle heat rate).
- Boiler Firing Type: Combination boilers are most often represented by three types: wall, tangential, and cyclone. The 'wall' category is the most general and represents variations such as opposed, top, cell, and others. The solution of boiler type affects the boiler efficiency and furnace emission factors.
- **Boiler Efficiency:** This is the percentage of fuel input energy transferred to steam in the boiler. The model default is to calculate the boiler efficiency using standard algorithms described in the literature. The efficiency is a function of energy losses due to inefficient heat transfer across the preheater, latent heat of evaporation, incomplete combustion, radiation losses, and unaccounted losses.
- **Excess Air for Furnace:** This is the excess theoretical air used for combustion. It is added to the stoichiometric air requirement calculated by the model. The value is calculated and based on the fuel type and boiler type.
- **Leakage Air at Preheater:** This is the additional excess air introduced because of leakage into the system at or beyond the air preheater. It is based on the stoichiometric air required for combustion. The leakage air increases the total gas volume downstream of the air preheater.
- **Gas Temperature Exiting Economizer:** This is the temperature of the flue gas exiting the economizer. The temperature is used in the calculation of the flue gas volume and air preheater performance.
- **Gas Temperature Exiting Air Preheater:** This is the temperature of the flue gas exiting the air preheater. The temperature is used in the calculation of the flue gas volume and air preheater performance.
- **Percent Water in Bottom Ash Sluice:** Bottom ash collected can be removed from the combustion bolier and disposed by sluicing the bottom ash with water. This is the percent water in the sluice.

#### **Base Plant Power Requirements**

These parameters specify the electrical power requirements of pulverizers, steam pumps, forced draft fans, cooling system equipment (fans and pumps), and other miscellaneous equipment excluding gas cleanup systems. These power requirements or penalties are expressed as a percent of a gross plant capacity and are used to calculate the net plant performance.

**Coal Pulverizer:** This is the power needed to run the coal pulverizers prior to the coal being blown into the boiler. It is also referred to as an

energy penalty to the base plant. The value is calculated and based on the fuel type. It is expressed as a percentage of the gross plant capacity.

- **Steam Cycle Pumps:** This is the power needed to operate the pumps in the steam cycle. It is also referred to as an energy penalty to the base plant. It is expressed as a percentage of the gross plant capacity.
- **Forced Draft Fans:** This is the power required for the forced draft fans and primary air fan expressed as a percentage of the gross plant capacity. It is also referred to as an energy penalty for the base plant.
- **Cooling System:** This is the power needed to run the pumps and other equipment for the water cooling system. It is expressed as a percentage of the gross plant capacity. It is also referred to as a base plant energy penalty.
- **Miscellaneous:** This is the power used by any other miscellaneous equipment in the base plant, not including equipment used for pollution control equipment. It is expressed as a percentage of the gross plant capacity. It is also referred to as a base plant energy penalty.

### **Base Plant Furnace Factors Inputs**

Inputs for the furnace factors that effect the major flow rates and concentrations of the gas and solids streams are entered on the **Furnace Factors** input screen.

This screen accepts inputs for the flue gas and ash products emitted from the boiler into the flue gas and ash streams. Factors in emissions include: incomplete combustion and thermodynamic equilibrium between gas species associated with the combustion products.

This screen's inputs are needed to calculate boiler efficiency and air pollutant emissions. The emission of carbon, ash, sulfur and nitrogen are specified by the United States Government's Environmental Protection Agency's (EPA) compilation of emission factors. Also included from the compilation are the incomplete transfer percentages of solid and gaseous forms of these substances.

This screen is available for all plant configurations.

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		Configure Plant	Set <u>P</u> ara	amete	ers		9	Get Res	ults	
	Ove <u>r</u> all Plant	Fuel <u>Base Plant</u> Emiss Constr	ion aint Mercury	<u>N</u> Con	Dx <u>T</u> ttro1 Co	]SP ntrol	<u>S</u> O2 Control	C <u>O</u> Captu	2 By-Proo are Mgmt	d.
		Title	Units	Unc	Value	Calc	Min	Max	Default	٦
Ι	1	Percent Ash Entering Flue Gas Str	%		80.00	K	0.0	100.0	calc	
Ι	2									
Ι	3	Sulfur Retained in Flyash	%		2.500	V	0.0	100.0	calc	
Ι	4	Percent of SOx as SO3	%		0.8000	V	0.0	100.0	calc	
Ι	5	Preheater SO3 Removal Efficiency	%		50.00	M	0.0	100.0	calc	
Ι	6									
Ι	7	Nitrogen Oxide Emission Rate	lb/MBtu		0.5656	M	0.0	10.00	calc	
Ι	8	Percent of NOx as NO	%		95.00	M	0.0	100.0	calc	
Ι	9									
Ι	10	Conc. of Carbon in Collected Ash	%		0.0		0.0	10.00	0.0	
Ι	11	Percent of Burned Carbon as CO	%		0.0		0.0	100.0	0.0	
Ι	12									
Ι	13									
	14									
I	15									
	16									
I	17									
I	18									
	Pro	cess Type: Base Plant	-							

Base Plant – Furn. Factors input screen.

Each parameter is described briefly below:

- **Percent Ash Entering Flue Gas Stream:** The default values for this parameter are a function of the fuel and boiler types and are based on the AP-42 EPA emission factors. Ash not entering the flue gas stream is assumed to be removed as bottom ash. This is also referred to as the overhead ash fraction.
- **Sulfur Retained in Flyash:** This parameter gives the percent of total sulfur input to the boiler that is retained in the flyash stream of a coal-fired power plant. The default values are a function of the selected boiler type and the coal rank as specified by the AP-42 EPA compilation of emission factors.
- **Percent of SO_x as SO₃:** This parameter quantifies the sulfur species in the flue gas stream. Sulfur not converted to  $SO_2$  is assumed to be converted to  $SO_3$ . The default value is based on emission factors derived by Southern Company³ and are a function of the selected coal.
- **Preheater SO₃ Removal Efficiency:** Sulfuric acid ( $H_2SO_4$ ) is created downstream of the boiler by the reaction of SO₃ with  $H_2O$ . A percent of the sulfuric acid is condensed on particulates in the preheater and removed from the flue gas. This parameter specifies the amount of SO₃ removed from the flue gas in the preheater as a function of the coal rank. The default value is taken from the removal efficiency reported in the literature (references are below). This efficiency then determines the mass of SO₃ removed from the flue gas in the collector. For more information see also:
  - www.netl.doe.gov/publications/proceedings/98/98fg/hardman.pdf
  - www.netl.doe.gov/publications/proceedings/98/98fg/rubin.pdf

³ Hardman, R., R. Stacy, et al. (1998). Estimating Total Sulfuric Acid Emissions from Coal-FIred Power Plants, Southern Company Services.

- **Nitrogen Oxide Emission Rate:** This parameter establishes the level of  $NO_x$  emissions from the boiler. The default values reflect the AP-42 EPA emission factors. It is a function of boiler firing method and the coal rank. The model calculates this value and expresses it in pounds of equivalent  $NO_2$  per ton of coal.
- **Percent of NO_x as NO:** This parameter establishes the level of nitric oxide (NO) in the flue gas stream. The remainder of the total NO_x emissions is assumed to be nitrogen dioxide (NO₂). The default parameters reflect the AP-42 EPA emission factors and are dependent on the fuel type.
- **Conc. of Carbon in Collected Ash:** This parameter accounts for retention of carbon in the fly ash and bottom ash. The amount of carbon in the collected ash streams is typically known. It is used to calculate the total unburned carbon in coal, boiler efficiency and flue gas composition.
- **Percent of Burned Carbon as CO:** This parameter accounts for any incomplete combustion in the furnace, and is used to calculate boiler efficiency and flue gas composition. The remainder is assumed to be  $CO_2$  or unburned carbon.

### **Base Plant Retrofit Cost Inputs**

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8			Title	Units	Unc	Value	Calc	Min	Max	Default	
*		1	Capital Cost Process Area								
		2	Steam Generator	retro \$/new \$		1.000		0.0	10.00	1.000	
		3	Turbine Island	retro \$/new \$		1.000		0.0	10.00	1.000	
		4	Coal Handling	retro \$/new \$		1.000		0.0	10.00	1.000	
		5	AshHandling	retro \$/new \$		1.000		0.0	10.00	1.000	
8		6	Water Treatment	retro \$/new \$		1.000		0.0	10.00	1.000	
<b>N</b> ?		7	Auxiliaries	retro \$/new \$		1.000		0.0	10.00	1.000	
		8									
		9									
		10									
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		Proc	ess Type: Base Plant			Costs are	in Con	stant 2000	dollars.	1	
		<u>1</u> . Perf	ormance 🖌 2. Furn. Factors 🗼	3. Retrofit Cost	<u>4</u> .0	Capital Cost		. O&M Co	st /		

Inputs for the capital costs of modifications to process areas of the base plant itself are entered on the **Retrofit Cost** input screen

Base Plant—Retrofit Cost input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Each Capital Cost Process Area is described briefly below.

- **Steam Generator:** This area accounts for the steam cycle equipment and pumps.
- **Turbine Island:** This area accounts for the turbine island and associated pumps.
- **Coal Handling:** This area accounts for the mechanical collection and transport equipment of coal in the plant.
- **Ash Handling:** This area accounts for the mechanical collection and transport of ash in the plant.
- **Water Treatment:** This area accounts for the pumps, tanks, and transport equipment used for water treatment.
- **Auxiliaries:** Any miscellaneous auxiliary equipment is treated in this process area.

### **Base Plant Capital Cost Inputs**

Inputs for the capital costs of the Combustion (Boiler) base plant itself are entered on the **Capital Cost** input screen.

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	(	Ove <u>r</u> all Plant	F <u>u</u> el	Base Plant	Emissi Constr	ion aint ∐	[ercury	<u>N</u> Cor	Ox ntro1 C	<u>F</u> SP ontrol	<u>S</u> O2 Control	C <u>O</u> Capt	2 By- ure M	Prod. gmt
9	IΓ			Title		U	uits	Unc	Value	Calc	Min	Max	Default	
*		1	Construction	Time		ye	ars		3.000		0.0	10.00	3.000	
		2												
R		3	General Facili	ities Capital		%]	PFC		10.00		0.0	100.0	10.00	
		4	Engineering d	& Home Office	Fees	%1	PFC		6.500		0.0	100.0	6.500	
		5	Project Conti	ngency Cost		%]	PFC		11.67		0.0	100.0	11.67	
?		6	Proces Conti	ngency Cost		%]	PFC		0.3000		0.0	100.0	0.3000	
<b>N</b> ?		7	Royalty Fees			%]	PFC		7.000e-02	!	0.0	100.0	7.000e-02	
<u> </u>		8												
		9	Pre-Pr	oduction Cost:	5									
		10	Fixed Operati	ing Cost		mo	nths		1.000		0.0	12.00	1.000	
		11	Variable Oper	rating Cost		mo	nths		1.000		0.0	12.00	1.000	
		12	Misc. Capital	lCost		%	TPI		2.000		0.0	10.00	2.000	
		13												
		14	Inventory Ca	pital		%	LbC		6.000e-02	!	0.0	10.00	6.000e-02	
		15												
		16												
		17												
		18	TCR Recover	ry Factor			%		100.0		0.0	100.0	100.0	
		Proc	ess Type:	Base Plant			-		Costs ar	e in Cor	ıstant 2000	dollars.		
	Ζ	<u>1</u> . Perf	ormance 🖌	<u>2</u> . Fum. Facto	rs 🖌	<u>3</u> . Retrofi	tCost )	4.0	Capital Cost		<u>5</u> . O&M Co	st /		

Base Plant—Capital Cost input screen

The necessary capital cost input parameters associated with the base plant are on this input screen. The capital cost parameters and terminology used in the IECM are based on the methodologies developed by the Electric Power Research Institute (EPRI). They have prepared a Technical Assessment Guide (TAG) in order to provide a consistent basis for reporting cost and revenues associated with the electric power industry. This system of reporting is used by a wide audience, including energy engineers, researchers, planners, and managers. The IECM has been developed around this TAG system so that costs associated with various technologies can be compared directly on a consistent basis and communicated in the language used by the audience listed above.

- **Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).
- **General Facilities Capital (GFC):** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

**Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

#### **Pre-Production Costs**

These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to O&M costs over a specified period of time (months).

- **Fixed Operating Cost:** Time period of fixed operating costs (operating and maintenance labor, administrative and support labor, and maintenance materials) used for plant startup.
- Variable Operating Cost: Time period of variable operating costs at full capacity (chemicals, water, and other consumables, and waste disposal changes) used for plant startup. Full capacity estimates of the variable operating costs will assume operations at 100% load.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) to finance the base plant as a percent of the TCR of a new power plant. This value is 100% for a new plant and may be set as low as 0% for a base plant that has been paid off.

### **Base Plant O&M Cost Inputs**

Inputs for the operation and maintenance costs of the Combustion (Boiler) base plant itself are entered on the **O&M Cost** input screen.

9	Configure Plant	Set Par	amete	ers	Ĩ		<u>G</u> et Res	sults
Ove <u>r</u> all Plant	Fuel Base Plant Mero	ury <u>N</u> Ox Control	<u>T</u> S Con	SP SP ttro1 Co	<u>3</u> O2 ontrol	C <u>O</u> 2 Capture	By-Pt Mg	rod. Stac <u>k</u>
	Title	Units	Unc	Value	Calc	Min	Max	Default
1	As-Delivered Coal Cost	\$/ton		27.70		0.0	160.0	calc
2	Waste Disposal Cost	\$/ton		9.360		0.0	30.00	9.360
3	Water Use	gallons/kWh		1.000		0.0	10.00	1.000
4	Water Cost	\$/1000 gal		0.7140	M	0.0	2.500	calc
5	Electricity Price (Base Plant)	\$/MWh		37.24	K	0.0	200.0	calc
6								
7	Number of Operating Jobs	number		20.00		0.0	100.0	20.00
8	Number of Operating Shifts	shifts/day		4.750		0.0	10.00	4.750
9	Operating Labor Rate	\$/hr		24.82		0.0	100.0	24.82
10								
11	Total Maintenance Cost	%TPC		1.850	K	0.0	100.0	calc
12	Maint. Cost Allocated to Labor	%TMC		35.00		0.0	100.0	35.00
13	Administrative & Support Cost	% total labor		7.000		0.0	100.0	7.000
14								
15	Real Escalation Rate	%/yr		0.0		0.0	10.00	0.0
16								
17								
18								

Base Plant—O&M Cost input screen

The EPRI TAG method of categorization has been used for operating and maintenance costs screens. It provides a consistent basis of reporting for a wider audience of users.

O&M costs are expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. The costs are broken down into two categories: variable and fixed. Variable costs include the costs of reagents, chemicals, water, and other materials consumed during plant operation. Fixed costs are associated with labor and overhead charges. All operating costs are subject to inflation.

- The base plant considers a more detailed breakdown for the costs associated with the fuel. Together they characterize the fuel costs. Each parameter is described briefly below.
- **As-Delivered Coal Cost:** This is the cost of the delivered coal in dollars per wet ton. The value is calculated by the IECM from the particular regional coal selected. It does not include any cleaning costs.
- **Waste Disposal Cost:** This is the bottom ash disposal cost for the base plant.
- Water Use: This is the water used by the base plant.
- Water Cost: This is the water cost as used for the base plant.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as combustion boiler and an air preheater.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- **Number of Operating Shifts:** This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work ( 3 shifts/day * 7 days/5

day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.
- **Real Escalation Rate:** This is the annual rate of increase of an expenditure due to factors such as resource depletion, increased demand, and improvements in design, manufacturing or construction techniques (negative rate). The real escalation rate does not include inflation.

### **Boiler Diagram**



The **Diagram** result screen displays an icon for the Combustion Boiler and values for major flows in and out of it.

Boiler—Diagram result screen.

Each result is described briefly below in flow order (not from top to bottom and left to right as they display on the screen).

#### **Fuel Entering Boiler**

- **Wet Fuel In:** Fuel flow rate into the boiler on a wet basis. Waste products removed prior to the burners are not considered here.
- **Mercury In:** This is the mass flow rate of total mercury entering the boiler. The mass reflects the molecular weight of elemental mercury.

#### **Boiler Performance**

- **Ash Entering Flue Gas:** Percent of the ash in coal exiting the boiler in the flue gas.
- **Mercury Removal:** Percent of the total mercury in coal removed from the boiler in the bottom ash.

#### **Air Entering Boiler**

- **Temperature:** Heated air temperature measured at the burners. This is generally determined by the combustion air temperature exiting the air preheater.
- **Heated Air:** Volumetric flow rate of the air at the burners, based on the air temperature at the burners and atmospheric pressure.

#### Flue Gas Exiting the Economizer

- **Temperature Out:** Temperature of the flue gas at the exit of the economizer.
- **Flue Gas Out:** Volumetric flow rate of the flue gas at the exit of the economizer, based on the temperature at the exit of the economizer and atmospheric pressure.
- **Fly Ash Out:** Total solids mass flow rate in the flue gas at the exit of the economizer. This includes ash, unburned carbon and unburned sulfur.
- **Mercury Out:** Total mass of mercury exiting the economizer. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

### **Bottom Ash**

- **Sluice Water:** Water added to the dry bottom ash. This water is added for transportation purposes.
- **Dry Bottom Ash:** Total solids mass flow rate of the bottom ash. This includes ash, unburned carbon and unburned sulfur. The value is given on a dry basis.
- Wet Bottom Ash: Total solids mass flow rate of the bottom ash for waste management. This includes dry bottom ash and sluice water. The value is given on a wet basis.

### **Boiler Flue Gas Results**

The **Flue Gas** result screen displays a table of quantities of flue gas components entering the combustion boiler in heated air and exiting the boiler in the flue gas. For each component, quantities are given in both moles and mass per hour.

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6		<u>(</u>	on	figure Plant	Ĭ	Se	t <u>P</u> aramete	rs	Ĭ	<u>c</u>	et Results	
		Overall Plant	F	uel <u>B</u> oile:	<u>A</u> ir Preheater	<u>N</u> Ox Control	Mercury	TSP Control	<u>S</u> O2 Control	C <u>O</u> 2 Captur	e By-Prod. <u>M</u> gmt	Stac <u>k</u>
3 X				Major F	lue Gas Compo	nenis	Heated Air In (Ib-moles/hr)	i Flue Gas ( (lb-moles/)	Dut Heated tr) (ton	l Air In ı/hr)	Flue Gas Out (ton/hr)	
	I		1	Nitrogen (N2)			1.091e+05	1.093e+0	5 15	528	1530	
	I		2	Oxygen (O2)			2.901e+04	4813	46	4.2	77.00	
<u> </u>	I		3	Water Vapor (F	42O)		3981	1.297e+0	4 35	.87	116.8	
<b>?</b>	I		4	Carbon Dioxide	e (CO2)		0.0	2.049e+0	4 0	.0	450.9	
?	I		5	Carbon Monox	ide (CO)		0.0	0.0	0	.0	0.0	
-11	I		6	Hydrochloric A	cid (HCl)		0.0	5.643	0	.0	0.1029	
	I		7	Sulfur Dioxide	(SO2)		0.0	214.2	0	.0	6.862	
	I		8	Sulfuric Acid (	equivalent SO3)		0.0	1.728	0	.0	6.916e-02	
	I		9	Nitric Oxide (N	0)		0.0	51.63	0	.0	0.7747	
	I		10	Nitrogen Dioxi	de (NO2)		0.0	2.717	0	.0	6.251e-02	
	II		11	Ammonia (NH3	Ŋ		0.0	0.0	0	.0	0.0	
	I		12	Argon (Ar)			0.0	0.0	0	.0	0.0	
	II		13	Total			1.421e+05	1.478e+0	5 20	128	2183	
	II		14									
	I		15									
		Process	Туре	Boiler	hie Clas	3 Capital C	nst / 40	&M Cost	<u> 5 To</u>	tal Cost		
	l	I.DR	-Gran	" <u>A</u> <u>2</u> .r.		2. Capital C	<u>4</u> .0	Action Close	A 2.10	nar Cost		

Boiler-Flue Gas result screen.

Each result is described briefly below.

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

### **Boiler Capital Cost Results**

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the Combustion Boiler.

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	ſ		<u>C</u> onfigure Plant	Ĩ	Set	t <u>P</u> ar	am	ters	Ĩ	Get	Results	
	ſ	Over Plar	rall Fuel Boiler A	ir eater	<u>N</u> Ox Control	Mer	cury	TSP Control	<u>S</u> O2 Control	C <u>O</u> 2 Capture	By-Prod. Mgmt	Stac <u>k</u>
*			Base Plant Process Area Co	sts	Capital ( (M\$)	Cost		Ba	se Plant Pla	nt Costs	Cap	ital Cost (M\$)
		1	Steam Generator		128.2	2	1	Process Faci	lities Capital		3	<mark>13.7</mark>
P		2	Turbine Island		92.79	)	2	General Facil	ities Capital		3	1.37
		3	Coal Handling		43.18	3	3	Eng. & Home	e Office Fees	,		:0.39
		4	Ash Handling		7.720		4	Project Conti	ingency Cos	t.	3	16.61
		5	Water Treatment		7.833	3	5	Process Con	tingency Co	st	U	.9412
2		0	Auxinaries		34.05	,	0	Derest Char	rges (AFUD) -	~)		2.94
<u></u>		1	riocess racindes Capital		515.7			Royalty Fees	s un (Stautaun) (	"oct		270
		0				_	0	Inventory (V	In (Startup) ( Vorking) Cat	vital	0	2418
		10				-	10	Total Capital	Requiremen	nt (TCR)	4	59.2
		11				_	11		1			
		12					12					
		13					13					
		14					14					
		15					15	Effective TC	R		4	<mark>.59.2</mark>
		Pro	ocess Type: Boiler		-			Costs are	e in Constan	t 2003 dolla	us.	
			1. Diagram 🔏 2. Flue Gas	<u>}</u>	Capital Co	ost /		<u>1</u> . O&M Cost	<u>5</u> .T	otal Cost	/	

Boiler—Capital Cost result screen.

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

### **Direct Capital Costs**

The direct capital costs described here apply to the "base power plant" without any of the environmental control options that are separately modeled in the IECM. While the purpose of the IECM is to model the cost and performance of emission control systems, costs for the base plant are also needed to properly account for precombustion control options that increase the cost of fuel, and affect the characteristics or performance of the base plant. Base plant costs are also needed to calculate the internal cost of electricity which determines pollution control energy costs.

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses. They are described in general below. The primary factors in the model that effect the capital cost of the base plant are the plant size, the coal rank, and the geographic location of the plant.

- **Steam Generator:** This area accounts for the steam cycle equipment and pumps.
- **Turbine Island:** This area accounts for the turbine island and associated pumps.
- **Coal Handling:** This area accounts for the mechanical collection and transport equipment of coal in the plant.

- **Ash Handling:** This area accounts for the mechanical collection and transport of ash in the plant.
- **Water Treatment:** This area accounts for the pumps, tanks, and transport equipment used for water treatment.
- **Auxiliaries:** Any miscellaneous auxiliary equipment is treated in this process area.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

### **Total Capital Costs**

- **Process Facilities Capital:** See definition above. This result is highlighted in yellow.
- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

**Effective TCR:** The TCR of the base plant that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the base plant.

### **Boiler O&M Cost Results**

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the combustion base plant. The variable O&M costs are calculated from the variable costs for fuel, water consumption and bottom ash disposal (from the furnace). The fixed O&M costs are based on maintenance and labor costs.

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			Variable Cost Component	O&M C (M\$/yı	ost ')		Fi	xed Cost Co	mponent	80 ()	M Cost I\$/yr)
B		1	Fuel	44.64		1	Operating L	abor		4	.974
e l		2	Water	1.185	_	2	Maintenanc	e Labor		2	2.504
		3	Disposal	0.1138	3	3	Maintenanc	e Material		4	.650
2		4	Utility Power Credit	-36.75	·	4	Admin. & St	apport Labor	r	0	.5234
<u>N?</u>		5	l otal Variable Costs	9,186	_	5	I otal Fixed (	Josts		1	2.65
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		15				15	Total O&M	Costs		2	2 <mark>1.84</mark>
		Pro	cess Type: Boiler	-			Costs ar	e in Constar	ut 2000 dolla	urs.	
			1. Diagram 🖌 2. Flue Gas 🖌 3	. Capital Co	st	4	. O&M Cost	<u>5</u> . T	otal Cost	/	

The Boiler—O&M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

### **Variable Cost Components**

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

- **Fuel:** The total cost of as-fired fuel. Minemouth cost, coal cleaning costs and transportation costs are all included.
- **Water:** The total cost of water consumed by the base plant for direct or reheat use.
- **Disposal:** The total cost of bottom ash disposal. The value is given on a wet ash basis. This does not consider by-product ash sold in commerce.
- Utility Power Credit: Power consumed by abatement technologies result in lower net power produced and lost revenue. The IECM charges each technology for the internal use of electricity and treats the charge as a

credit for the base plant. When comparing individual components of the plant, these utility charges are taken into consideration. For total plant costs they balance out and have no net effect on the plant O&M costs.

**Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

### **Boiler Total Cost Results**

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the boiler.

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				Cost Com	ponent		M\$/yr	\$/MWh	Percent Tot	tal	
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<u> </u>		3 4	Total Annu Annualize	u <mark>al O&amp;M Co</mark> 1 Capital Cos	st it		21.84 72.19	9.813 32.44	23.22 76.78		
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	Process Type	Во	iler		-		Costs	are in Constan	t 2000 dollar:	s.	
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Boiler—Total Cost result screen.

### **Cost Component**

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# **Auxiliary Boiler**

An **Auxiliary Boiler System** is available as an option from within the amine scrubber system. It is specified from the **Set Parameters** program area of the **CO2 Capture** configuration input screen using the **Process Type** pull-down menu at the bottom of the screen.



Auxiliary Boiler – Process Type

Input parameters are included as part of the amine system and not specified separately. Several performance result screens are provide separately for the auxiliary boiler system, but cost results are incorporated into the amine system. The following sections describe the results that are displayed explicitly for the auxiliary boiler system.

### **Auxiliary Boiler Diagram**

The **Diagram** result screen displays an icon for the Auxiliary Boiler and values for major flows in and out of it. The auxiliary boiler is available in the **Combustion (Boiler)** and **Combustion (Turbine)** plant types when an amine scrubber is configured. It is a sub-system inside the amine scrubber when the auxiliary boiler option is added.



Auxiliary Boiler – Diagram.

Each result is described briefly below.

#### Air and Fuel

Air In: The mass flow rate of fresh air is provided. This is the stoichiometric amount of air and excess air as specified on the  $CO_2$  Capture input screen.

**Natural Gas In:** This is the flow rate of natural gas necessary to provide the heat necessary to provide regeneration heat to the MEA regenerator.

#### **Steam and Power Generation**

**Steam Supply:** This is the total steam energy required by the  $CO_2$  regenerator. The steam is supplied to the MEA regenerator.

**Electricity:** Low pressure steam generated by the auxiliary boiler may be used to generate electricity in a steam turbine. This electricity supplements that produced by the base plant.

#### Flue Gas Exiting Aux. Boiler System

**CO₂:** This is the flow rate of emission dioxide from the auxiliary boiler. It is emitted from a secondary stack.

**Equivalent SO₂:** This is the emission rate of sulfur dioxide from the auxiliary boiler. It is emitted from a secondary stack.

**Equivalent NO₂:** This is the emission rate of nitrogen dioxide from the auxiliary boiler. It is emitted from a secondary stack.

### **Auxiliary Boiler Natural Gas Results**

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types. It is a sub-system inside the amine scrubber when the auxiliary boiler option is added.

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<b>S</b>				Na	tural Gas Com	ponents	Natural Gas In (Ib-moles/hr)	Natural Gas In (tons/hr)		
B			1	Carbon Mo	noxide (CO)		0.0	0.0		
P			2	Hydrogen (	H2)		0.0	0.0		
			3	Methane (C	H4)		4647	37.27		
			4	Ethane (C2H	16)		880.4	13.24		
			5	Propane (C3	H8)		0.0	0.0		
?			6	Hydrogen S	ulfide (H2S)		0.0	0.0		
▶?			7	Carbonyl St	ilfide (COS)		0.0	0.0		
<u> </u>			8	Ammonia (1	чнз)		0.0	0.0		
			9	Hydrochlor	ic Acid (HCI)		0.0	0.0		
			10	Carbon Dio	ade (CO2)		0.0	0.0		
			11	Water Vapo	r(n20) 20		0.0	0.0		
			12	Argon (Ar)	4)		44.38	0.0243		
			13	Aigoti (Ai)			0.0	0.0		
			14	Total	)		5572	0.0 51.12		
	Proc	ess Type: Au	x Boile	tural Gas	▼ 3 Flue G	] as /	4 Costs			
			<u>Z</u> . 198	itural Gas	<u></u> Fide O		4.00sts /			

Auxiliary Boiler System – Natural Gas.

#### **Natural Gas Components**

The breakdown of components in the natural gas entering the auxiliary boiler are described briefly below:

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H₂): Total mass of hydrogen.

Methane (CH₄): Total mass of methane.

Ethane (C₂H₆): Total mass of ethane.

Propane (C₃H₈): Total mass of propane.

Hydrogen Sulfide (H₂S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH₃): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Nitrogen (N₂): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O₂): Total mass of oxygen.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

### **Auxiliary Boiler Flue Gas Results**

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.

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		Ove <u>r</u> all Plant	F <u>u</u> el	Boil	er <u>A</u> ir Prehea	ter Control	Mercury	<u>T</u> SP Control	S Cor	D2 C <u>O</u> 2 ntrol Capture	By-Prod. Mgmt	Stac <u>k</u>
 ₩ ₩					Maj	or Flue Gas Cor	monents	Flue Gas (D-mole:	; Out s/hr)	Flue Gas Out (tons/hr)		
B				1	Nitrogen (P	12)		5.030e	+04	704.5		
P				2	Oxygen (O	2)		990.1	1	15.84		
				3	Water Vap	or (H2O)		1.194e	+04	107.5		
				4	Carbon Dic	xide (CO2)		6408	В	141.0		
				5	Carbon Mc	moxide (CO)		0.0		0.0		
8				6	Hydrochlor	ric Acid (HCI)		0.0		0.0		
2				7	Sulfur Diox	ide (SO2)		0.0		0.0		
<u></u>				8	Sulfuric Ac	id (equivalent S	03)	0.0		0.0		
				9	Nitric Oxide	e (NO)		0.0		0.0		
				10	Nitrogen D	ioxide (NO2)		0.0		0.0		
				11	Ammonia (	NH3)		0.0		0.0		
				12	Argon (Ar)			0.0		0.0		
				13	Total			6.964e	+04	968.9		
				14								
				15								
		Process	Type: A	ux Boil	er	•						
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Auxiliary Boiler System - Flue Gas result screen

### **Major Flue Gas Components**

Natural gas fired in the auxiliary boiler produces a flue gas. This flue gas is emitted to the atmosphere via a secondary stack. Each component is described briefly below:

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCI): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **Auxiliary Boiler Costs Results**

This screen is only available for the Combustion (Boiler) and Combustion (Turbine) plant types.

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		Overall Plant Fi	iel <u>B</u> oiler	<u>A</u> ir Preheat	ter Control	Mercury	TSP Control C	<u>3</u> O2 ontrol C	CO2 By-Prod apture Mgmt	Stack
*						See Also	1			
B					1 Auxiliary b	oiler costs are	located			
P					2 on the Amin	ne System cost T	screens.	-		
					3 Use the Pro	icess 1ype: me	u below.	-		
					5			-		
2					6					
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				-	8			-		
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				1	2			-		
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		<u>1</u> . Diagram	<u>2</u> . Natur	al Gas	<u>3</u> . Flue G	as	4. Costs			

Amine System – Total Cost result screen.

The **Costs** result screen displays a note, pointing the user to the amine system cost screens. Because the auxiliary boiler is a sub-system of the amine system, the costs associated with the **Auxiliary Boiler** are displayed by the **Amine System** cost screens. View these by selecting the **Amine System** from the **Process Type** menu on the bottom of the screen.

# Gasifier

This gasifier chapter describes the coal gasification equipment used in the IGCC plant types.

# **Gasifier Performance Inputs**

This screen is only available for the IGCC plant type.

	<u>C</u> onfigure Plant	Set <u>P</u> a	ramet	ers			<u>G</u> et Res	sults
Ove <u>r</u> all Pla	ant F <u>u</u> el <u>A</u> ir Separation	Gasifier Su Area Rer	ilfur noval	C <u>O</u> 2 Captu	re Po	wer <u>B</u> lock	By-Proc Mgmt	i. Stac <u>k</u>
	Title	Units	Unc	Value	Calc	Min	Max	Default
1	Gasifier Area							
2	Gasifier Temperature	°F		2450 💌		Menu	Menu	2450
3	Gasifier Pressure	psia		615.0		600.0	650.0	615.0
4	Total Water or Steam Input	mol H2O/mol C		0.4419	V	0.0	1.000	calc
5	Oxygen Input from ASU	mol O2/mol C		0.4550	V	0.0	1.000	calc
6	Total Carbon Loss	%		3 🔻		Menu	Menu	3
7	Sulfur Loss to Solids	%		0.0	V	0.0	100.0	calc
8	Coal Ash in Raw Syngas	%		0.0	V	0.0	100.0	calc
9	Percent Water in Slag Sluice	%		0.0	V	0.0	99.00	calc
10								
11	Number of Operating Trains	integer		2	V	Menu	Menu	Calc
12	Number of Spare Trains	integer		1 -		Menu	Menu	1
13								
14	Raw Gas Cleanup Area							
15	Particulate Removal Efficiency	%		100.0	M	0.0	100.0	calc
16								
17	Power Requirement	% MWg		1.095		0.0	6.000	calc
18								

Gasifier – Performance input screen.

#### **Gasifier Area**

- **Gasifier Temperature:** This is the temperature of the syngas exiting GE Entrained-Flow Reactor.
- **Gasifier Pressure:** This is the pressure of the syngas exiting GE Entrained-Flow Reactor.
- **Total Water-or-Steam Input:** This is the ratio of water to carbon in the coal slurry.

- **Oxygen Input from ASU:** The GE gasifier requires a constant value for the oxygen  $(O_2)$  in the oxidant to carbon (C) in coal ratio.
- Total Carbon Loss: This the percent of carbon in the fuel that is lost.
- **Sulfur Loss to Solids:** This is the percent of the sulfur in coal that is lost in the slag.
- **Coal Ash in Raw Syngas:** This is the percent of ash in the coal that is in the syngas.
- **Percent Water in Slag Sluice:** This is the percent of the slag sluice that is water.
- **Number of Operating Trains:** This is the total number of operating trains. It is used primarily to calculate capital costs. The value must be an integer
- **Number of Spare Trains:** This is the total number of spare trains. It is used primarily to calculate capital costs. The value must be an integer.

#### **Raw Gas Cleanup Area**

- Fly Ash Removal Efficiency: This is the percentage of the ash which is removed by the raw gas cleanup process.
- **Power Requirement:** This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required.

### **Gasifier Syngas Inputs**

The syngas generated by the gasifier is calculated as a function of the coal, water, and oxidant input flow rates, the carbon loss, and the gasifier temperature. The composition may be changed by the user. The location of this syngas composition is after the gasification but prior to the low temperature cooling and water quench. Hence, the steam content of the syngas is typically in the 10 - 15% by volume range. This screen is only available for the IGCC plant type.

Overall Plant         Fuel         Air Separation         Out functions         Courter of the second Removal         Statistics         By-Prod Mgent         Statistics           Image: Carbon Monoxide (CO)         vol %         38.07         0.0         100.0         calc         Image: Carbon Monoxide (CO)         vol %         38.07         0.0         100.0         calc           4         Methane (CH4)         vol %         38.07         0.0         100.0         calc           5         Ethane (CH4)         vol %         0.5559         0.0         100.0         calc           6         Propane (C3H8)         vol %         0.5629         0.0         100.0         calc           7         Hydrogen Sulfide (H2S)         vol %         0.5629         0.0         100.0         calc           8         Carbonyl Sulfide (COS)         vol %         0.5629         0.0         100.0         calc           9         Ammonia (NH3)         vol %         0.5629         0.0         100.0         calc           10         Hydrochonic Acid (HCI)         vol %         1.400e.02         0.0         100.0         calc           10         Hydrochonic Acid (HCI)         vol %         1.47.0         0.0		Configure Pla	mt โ	S	Set Perometers Get Results							
Overall Plant         Fuel         Air Separation         Casifier Ares         Suthur Removal         Oue Capture         Power Block         By-Prod Mgmt         Star           Image: Carbon Monoxide (CO)         vol %         38.07         Ø         0.0         100.0         calc           4         Methane (CH4)         vol %         38.07         Ø         0.0         100.0         calc           5         Ethane (CH4)         vol %         0.5559         Ø         0.0         100.0         calc           6         Propane (C3H8)         vol %         0.5559         Ø         0.0         100.0         calc           7         Hydrogen Sulfide (H2S)         vol %         0.0         Ø         0.0         100.0         calc           6         Propane (C3H8)         vol %         0.5629         Ø         0.0         100.0         calc           7         Hydrogen Sulfide (H2S)         vol %         0.5629         Ø         0.0         100.0         calc           8         CarbonJSulfide (COS)         vol %         0.598e-03         Ø         0.0         100.0         calc           10         Hydrochloric Acid (HC1)         vol %         1.400e-02         Ø	,					men	v	Ļ		<u>O</u> et Res	vui s	
Title         Units         Unc         Value         Calc         Min         Max         Default           1         Eaw Syngas Composition         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         - <td< th=""><th colspan="2">Overall Plant Fuel <u>A</u>ir Separation</th><th>Gasifier Area</th><th colspan="3">Area Removal</th><th>e Po</th><th>wer <u>B</u>lock</th><th>By-Prod Mgmt</th><th>' Stac</th></td<>	Overall Plant Fuel <u>A</u> ir Separation		Gasifier Area	Area Removal			e Po	wer <u>B</u> lock	By-Prod Mgmt	' Stac		
I         Raw Syngas Composition         vol         38.07         vol         0.0         100.0         calc           2         Carbon Monoxide (CO)         vol %         38.07         vol         0.0         100.0         calc           3         Hydrogen (H2)         vol %         34.39         vol 0.0         100.0         calc           4         Methane (CH4)         vol %         0.5559         vol %         0.0         100.0         calc           5         Ethane (C2H6)         vol %         0.0         vol %         0.0         100.0         calc           6         Propane (C3H8)         vol %         0.0         vol %         0.0         100.0         calc           7         Hydrogen Sulfide (H2S)         vol %         0.5629         vol %         0.0         100.0         calc           9         Armonia (NH3)         vol %         8.998e.03         vol %         10.0         calc           10         Hydrochloric Acid (HC1)         vol %         1.400e.02         vol %         0.0         100.0         calc           12         Moisture (H2O)         vol %         1.400e.02         vol %         0.0         100.0         calc		Т	ïtle	Uni	ts	Unc	Value	Calc	Min	Max	Default	
2         Carbon Monoxide (CO)         vol %         38.07         ½         0.0         100.0         calc           3         Hydrogen (H2)         vol %         34.39         ½         0.0         100.0         calc           4         Methane (CH4)         vol %         0.5559         ½         0.0         100.0         calc           5         Ethane (C2H6)         vol %         0.0         ½         0.0         100.0         calc           6         Propane (C3H8)         vol %         0.0         ½         0.0         100.0         calc           7         Hydrogen Sutifide (H2S)         vol %         0.5629         ½         0.0         100.0         calc           9         Armonia (NH3)         vol %         2.800e.02         ½         0.0         100.0         calc           10         Hydrochoic Acid (HC1)         vol %         1.400e.02         ½         0.0         100.0         calc           11         Carboryl Sutifide (CO2)         vol %         1.400e.02         ½         0.0         100.0         calc           12         Mistrue (H2O)         vol %         1.400e.02         ½         0.0         100.0         calc	1	Raw Syngas	Composition									
3         Hydrogen (H2)         vol%         34.39         ✓         0.0         100.0         calc           4         Methane (CH4)         vol%         0.5559         ✓         0.0         100.0         calc           5         Ethane (CH6)         vol%         0.0         0.0         100.0         calc           6         Propane (C3H8)         vol%         0.0         ✓         0.0         100.0         calc           7         Hydrogen Sulfide (H2S)         vol%         0.5629         ✓         0.0         100.0         calc           8         Carbonyl Sulfide (COS)         vol%         2.800e-02         ✓         0.0         100.0         calc           9         Anmonia (NH3)         vol%         8.998e-03         ✓         0.0         100.0         calc           10         Hydrochloric Acid (HCI)         vol%         1.400e-02         ✓         0.0         100.0         calc           11         Carbon Dioxide (CO2)         vol%         14.70         ✓         0.0         100.0         calc           12         Moisture (H2O)         vol%         9.898         ✓         0.0         100.0         calc           13<	2	Carbon Monoxid	le (CO)	vol	%		38.07	V	0.0	100.0	calc	
4         Methane (CH4)         vol%         0.5559         ½         0.0         100.0         calc           5         Ethane (CH4)         vol%         0.0         ¾         0.0         100.0         calc           6         Propane (C3H8)         vol%         0.0         ¾         0.0         100.0         calc           7         Hydrogen Suffide (H2S)         vol%         0.5629         ¾         0.0         100.0         calc           8         Carbonyl Sulfide (COS)         vol%         0.5629         ¾         0.0         100.0         calc           9         Ammonia (NH3)         vol%         8.998e.03         ¥         0.0         100.0         calc           10         Hydrochloric Acid (HCI)         vol%         1.400e.02         ¾         0.0         100.0         calc           12         Moisture (H2O)         vol%         14.70         4         0.0         100.0         calc           13         Nitrogen (N2)         vol%         0.9008         ¾         0.0         100.0         calc           14         Argon (Ar)         vol%         0.8659         ¾         0.0         100.0         calc	3	Hydrogen (H2)		vol	%		34.39	V	0.0	100.0	calc	
5         Ethane (C2H6)         vol%         0.0         ½         0.0         100.0         calc           6         Propane (C2H8)         vol%         0.0         ½         0.0         100.0         calc           7         Hydrogen Sutifie (H2S)         vol%         0.5629         ½         0.0         100.0         calc           8         Carboryl Sutifie (COS)         vol%         2.800e 02         ½         0.0         100.0         calc           9         Ammoria (NH3)         vol%         8.998e.03         ½         0.0         100.0         calc           10         Hydrochloric Acid (HCt)         vol%         1.400e.02         ½         0.0         100.0         calc           11         Carbon Dioxide (CO2)         vol%         1.400e.02         ½         0.0         100.0         calc           12         Moisture (H2C)         vol%         1.400e.02         ½         0.0         100.0         calc           13         Nitrogen (N2)         vol%         9.898         ½         0.0         100.0         calc           14         Argon (Az)         vol%         0.8659         ½         0.0         100.0         calc <td>4</td> <td>Methane (CH4)</td> <td></td> <td>vol 1</td> <td>%</td> <td></td> <td>0.5559</td> <td>V</td> <td>0.0</td> <td>100.0</td> <td>calc</td>	4	Methane (CH4)		vol 1	%		0.5559	V	0.0	100.0	calc	
6         Propane (C3H8)         vol%         0.0         ½         0.0         100.0         calc           7         Hydrogen Suffide (H2S)         vol%         0.5629         ¥         0.0         100.0         calc           8         Carbonyl Suffide (H2S)         vol%         2.800e.02         ¥         0.0         100.0         calc           9         Ammonia (HH3)         vol%         8.998e.03         ¥         0.0         100.0         calc           10         Hydrochloric Acid (HCI)         vol%         8.998e.03         ¥         0.0         100.0         calc           11         Carbon Dioxide (CO2)         vol%         14.400e.02         ¥         0.0         100.0         calc           12         Moisture (H2O)         vol%         9.898         ¥         0.0         100.0         calc           13         Nitrogen (N2)         vol%         0.9008         Ø         0.0         100.0         calc           14         Argon (Ar)         vol%         0.8659         Ø         0.0         100.0         calc           14         Argon (Ar)         vol%         100.0         ¥         0.0         100.0         calc	5	Ethane (C2H6)		vol	%		0.0	V	0.0	100.0	calc	
7         Hydrogen Sulfide (H2S)         vol%         0.5629         ½         0.0         100.0         calc           8         Carboryl Sulfide (COS)         vol%         2.800e.42         ¾         0.0         100.0         calc           9         Ammonia (NH3)         vol%         8.998e.03         ¾         0.0         100.0         calc           10         Hydrochloric Acid (HCI)         vol%         1.400e.02         ¾         0.0         100.0         calc           11         Carbor Dioxide (CO2)         vol%         14.70         ¾         0.0         100.0         calc           12         Moisture (H2O)         vol%         9.898         ½         0.0         100.0         calc           13         Nitrogen (N2)         vol%         0.9008         ¾         0.0         100.0         calc           14         Argon (Ar)         vol%         0.8659         ¾         0.0         100.0         calc           15         Total         vol%         100.0         ¾         0.0         100.0         calc           16 <td>6</td> <td>Propane (C3H8)</td> <td></td> <td>vol</td> <td>%</td> <td></td> <td>0.0</td> <td>V</td> <td>0.0</td> <td>100.0</td> <td>calc</td>	6	Propane (C3H8)		vol	%		0.0	V	0.0	100.0	calc	
8         Carbonyl Sulfide (COS)         vol %         2.800e.02         ½         0.0         100.0         calc           9         Annonia (MH3)         vol %         8.998e.03         ¥         0.0         100.0         calc           10         Hydochloic Acid (HCI)         vol %         1.400e.02         ¥         0.0         100.0         calc           11         Carbon Dioxide (CO2)         vol %         14.70         ¥         0.0         100.0         calc           12         Moisture (H2O)         vol %         9.898         ¥         0.0         100.0         calc           13         Nitrogen (N2)         vol %         0.9008         ¥         0.0         100.0         calc           14         Argon (A2)         vol %         0.8659         Ø         0.0         100.0         calc           15         Total         vol %         100.0         ¥         0.0         100.0         calc           16	7	Hydrogen Sulfid	e (H2S)	vol	%		0.5629	V	0.0	100.0	calc	
9         Ammonia (NH3)         vol %         8.998e.03         ½         0.0         100.0         calc           10         Hydrochloric Acid (HC1)         vol %         1.400e.02         ✓         0.0         100.0         calc           11         Carbon Dioxide (CO2)         vol %         14.70         ½         0.0         100.0         calc           12         Moisture (H2O)         vol %         9.898         ½         0.0         100.0         calc           13         Nitrogen (N2)         vol %         0.9008         ½         0.0         100.0         calc           14         Argon (A2)         vol %         0.8659         ✓         0.0         100.0         calc           15         Total         vol %         100.0         ½         0.0         100.0         calc           16                   17	8	Carbonyl Sulfide	(COS)	vol	%		2.800e-02	V	0.0	100.0	calc	
10         Hydrochloric Acid (HCt)         vol%         1.400e.02         ½         0.0         100.0         calc           11         Carbon Dioxide (CO2)         vol%         14.70         ½         0.0         100.0         calc           12         Moisture (H2O)         vol%         9.898         ½         0.0         100.0         calc           13         Nitrogen (N2)         vol%         0.9008         ½         0.0         100.0         calc           14         Argon (Ar)         vol%         0.8659         ½         0.0         100.0         calc           15         Total         vol%         100.0         ½         0.0         100.0         calc           16	9	Ammonia (NH3)		vol	%		8.998e-03	V	0.0	100.0	calc	
I1         Carbon Dioxide (CO2)         vol%         14.70         ¥         0.0         100.0         calc           12         Moisture (H2O)         vol%         9.898         ¥         0.0         100.0         calc           13         Nitrogen (N2)         vol%         0.9008         ¥         0.0         100.0         calc           14         Argon (Ar)         vol%         0.8659         ¥         0.0         100.0         calc           15         Total         vol%         100.0         ¥         0.0         100.0         calc           16                   17	10	Hydrochloric Ac	id (HCI)	vol	%		1.400e-02	V	0.0	100.0	calc	
12         Moisture (H2O)         vol%         9.898         2         0.0         100.0         calc           13         Nitrogen (N2)         vol%         0.9008         2         0.0         100.0         calc           14         Argon (Ar)         vol%         0.8659         2         0.0         100.0         calc           15         Total         vol%         100.0         2         0.0         100.0         calc           16                   17	11	Carbon Dioxide (	CO2)	vol	%		14.70	M	0.0	100.0	calc	
13         Nitrogen.(N2)         vol %         0.9008         ☑         0.0         100.0         calc           14         Argon.(Ar)         vol %         0.8659         ☑         0.0         100.0         calc           15         Total         vol %         100.0         ☑         0.0         100.0         calc           16                    17	12	Moisture (H2O)		vol	%		9.898	M	0.0	100.0	calc	
14         Argon (År)         vol%         0.8659         2         0.0         100.0         calc           15         Total         vol%         100.0         2         0.0         100.0         calc           16                    17	13	Nitrogen (N2)		vol	%		0.9008	M	0.0	100.0	calc	
15         Total         vol %         100.0         2         0.0         100.0         calc           16	14	Argon (Ar)		vol	%		0.8659	M	0.0	100.0	calc	
16 17	15	Total		vol	%		100.0	M	0.0	100.0	calc	
17	16											
	17											
18	18											

Gasifier – Gas Flow result screen..

#### **Raw Syngas Composition**

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H₂):Total mass of hydrogen.

Methane (CH₄):Total mass of methane.

Ethane (C₂H₆):Total mass of methane.

**Propane (C₃H₈):**Total mass of methane.

Hydrogen Sulfide (H₂S):Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH₃): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Moisture (H₂O): Total mass of water vapor.

Nitrogen (N₂): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **Gasifier Retrofit Cost Inputs**

This screen is only available for the IGCC plant type.

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6	<u>C</u> onfigure Plant	Set <u>P</u> ar	Set <u>P</u> arameters						
	Overall Plant Fuel <u>A</u> ir Separation	Gasifier Su Area Rem	fur oval	C <u>O</u> 2 Captu	are Po	wer <u>B</u> lock	By-Prod Mgmt	1. Stac <u>k</u>	
6	Title	Units	Unc	Value	Calc	Min	Max	Default	
8	1 Capital Cost Process Area								
6	2 Coal Handling	retro \$/new \$		1.000		0.0	10.00	1.000	
2	3 Gasifier Area	retro \$/new \$		1.000		0.0	10.00	1.000	
	4 Low Temperature Gas Cooling	retro \$/new \$		1.000		0.0	10.00	1.000	
1	5 Process Condensate Treatment	retro \$/new \$		1.000		0.0	10.00	1.000	
	6								
	7								
<u>_</u>	8								
<u>9</u>	9		_						
-	11								
	12								
	13								
	14								
	15								
	16								
	17								
	18								
	Process Type: GE	7							
	1. Performance 🔏 2. Syngas Out 🗼	3. Retrofit Cost	4.0	apital Cost	<u> </u>	5. O&M Co	st /		

Gasifier – Retrofit Cost input screen.

### **Capital Cost Process Area**

- **Coal Handling:** Coal handling involves unloading coal from a train, storing the coal, moving the coal to the grinding mills, and feeding the gasifier with positive displacement pumps. A typical coal handling section contains one operating train and no spare train. A train consists of a bottom dump railroad car unloading hopper, vibrating feeders, conveyors, belt scale, magnetic separator, sampling system, deal coal storage, stacker, reclaimer, as well as some type of dust suppression system. Slurry preparation trains typically have one to five operating trains with one spare train. The typical train consists of vibrating feeders, conveyors, belt scale, rod mills, storage tanks, and positive displacement pimps to feed the gasifiers. All of the equipment for both the coal handling and the slurry feed are commercially available. A regression model was developed for the direct cost of coal handling and slurry preparation using the data collected for possible independent variables affecting direct capital cost. Coal feed rate to the gasifier on as-received basis is the most common and easily available independent variable. The direct cost model for the coal handling is based upon the overall flow to the plant rather than on a per train basis.
- **Gasifier Area:** The GE gasification section of an IGCC plant contains gasifier, gas cooling, slag handling, and ash handling sections. For IGCC plants of 400 MW to 1100 MW, typically 2 to 4 operating gasification trains are used along with one spare train. The mass flow of coal to the gasifier is assumed to be between 3000 and 3500 tons/day per train (as_received).
- **Low Temperature Gas Cooling:** The low temperature gas cooling section includes a series of three shell and tube exchangers. The number of operating trains are estimated based on the total syngas mass flow rate and the range of syngas flow rates per train used.

**Process Condensate Treatment:** This model is based upon one data point from AP-5950. Because the treated process condensate is used as make-up to the gas scrubbing unit, and because blowdown from the gas scrubbing unit is the larger of the flow streams entering the process condensate treatment section, it is expected that process condensate treatment cost will depend primarily on the scrubber blowdown flow rate.

# **Gasifier Capital Cost Inputs**

This screen is only available for the IGCC plant type.

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		<u>(</u>	<u>C</u> onfigure Pla	nt Ì	S	et <u>P</u> ar	amete	ers	Ì		<u>G</u> et Res	ults	
		Ove <u>r</u> all Pla	nt F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> u Rem	lfur ioval	C <u>O</u> 2 Captu	rePo	wer <u>B</u> lock	By-Prod Mgmt	l. St	ac <u>k</u>
9			Т	itle	Uni	ts	Unc	Value	Calc	Min	Max	Default	
*		1	Construction Tim	ıe	yea	rs		4.000		0.2500	10.00	4.000	
		2											
		3	General Facilities	Capital	%PI	°C		15.00		0.0	50.00	15.00	
		4	Engineering & H	ome Office Fees	%PF	°C		10.00		0.0	50.00	10.00	
<u>B</u>	Ш	5	Project Continger	ncy Cost	%PF	°C		15.00		0.0	100.0	15.00	
<b>+</b>	Ш	6	Process Conting	ency Cost	%PF	°C		12.26		0.0	100.0	calc	
		7	Royalty Fees		%PF	°C		0.5000		0.0	10.00	0.5000	
		8											
<u>¥</u>	Ш	9	Pre-Produ	ction Costs									
N?	Ш	10	Months of Fixed	0&M	moni	ths		1.000		0.0	12.00	1.000	
	Ш	11	Months of Variat	ole O&M	moni	ths		1.000		0.0	12.00	1.000	
		12	Misc. Capital Co:	st	%T	PI		2.000		0.0	10.00	2.000	
		13											
		14	Inventory Capita	1	%11	PC .		1.000		0.0	10.00	1.000	
	Ш	15							-				
		16											
		17	TODD		0/			100.0		0.0	200.0	100.0	
		18	TOR Recovery F	actor	%			100.0		0.0	200.0	100.0	
		Proc	ess Type: GE			Y							
		<u>1</u> . Perf	ormance / <u>2</u> .	Syngas Out 🛛	<u>3</u> . Retrofit (	Cost	<u>4</u> .0	apital Cost		<u>5</u> . O&M Co	st /		

Gasifier – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

**Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

- **General Facilities Capital (GFC)**: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-

by-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.
  - **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
  - **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
  - **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

### **Gasifier O&M Cost Inputs**

This screen is only available for the IGCC plant type.

	<u>(</u>	<u>C</u> onfigure Plant		Se	t <u>P</u> ara	mete	ers			<u>G</u> et Res	ults	
Ov	Dverall Plant Fuel <u>A</u> ir Separation		Gasifier Area	<u>S</u> ulfi Remo	ur val	C <u>O</u> 2 Captu	ire Po	wer <u>B</u> lock	By-Prod. Mgmt St		ıc <u>k</u>	
		Title		Unit	s	Unc	Value	Calc	Min	Max	Default	
	1	Slag Disposal Cost		\$/to:	n		13.07	V	0.0	30.00	calc	
	2	WaterCost		\$/1000	gal		0.8316	V	0.0	2.500	calc	
	3	Electricity Price (Bas	e Plant)	\$/MV	Vh		52.94	M	0.0	200.0	calc	
	4											
	5	Number of Operating	gJobs	jobs/si	hift		6.670		0.0	30.00	6.670	
	6	Number of Operating	g Shifts	shifts/	day		4.750		0.0	10.00	4.750	
	7	Operating Labor Rat	e	\$/h:	r		24.82		0.0	100.0	24.82	
	8											
	9	Total Maintenance (	Cost	%TP	C		3.723		0.0	10.00	calc	
	10	Maint. Cost Allocat	ed to Labor	% tot	tal		40.00		0.0	100.0	40.00	
	11	Administrative & Su	pport Cost	% total 1	labor		30.00		0.0	100.0	30.00	
	12											
	13											
	14											
	15											
	16											
	17											
	18											
	Proc	ess Type: GE			7		Costs are	in Con	stant 2005	dollars.		

Gasifier – O&M Cost input screen.

Inputs for O&M costs are entered on the **Gasifier O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Slag Disposal Cost: This is the solid disposal cost per ton.

Water Cost: This is the cost of the water per 1000 gallons.

- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as an air separation unit, gasifier and the power block.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work ( 3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- **Maint. Cost Allocated to Labor:** Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

## **Gasifier Diagram**

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	ľ	Ove <u>r</u> all Plant	F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac <u>k</u>
		Cold Gas Eff Temperature Coal In (ton Water In (to Oxidant In (t	iciency, HHV i In (°F) s/hr) tons/hr)	77.68 270.0 186.0 81.65 176.9	щ,		Aatewater rreatment Discharge	i <b>ch Water</b> Temperature Out ( Pressure Out (psia Syngas Out (tons/ Syngas Out (acfm)	♥F)     ))     ))   :	101.0 572.0 426.3 2.630e+05
		Sluice Wate: Process Ty	r (tons/hr) <b>pe:</b> GE	0.0	] 			• Wet Slag (tons/hr)	)	17.59
		<u>1</u> . Diagr	ram	<u>2</u> . Oxidant	<u>3</u> . Synga	is <u>4</u> .1	Capital Cost	<u>5</u> . O&M Cost	<u>6</u> . T	otalCost /

This screen is only available for the IGCC plant type.

Gasifier – Diagram result screen.

The **Gasifier Diagram** result screen displays an icon for the Gasifier Unit and values for major flows in and out of it. Each result is described briefly below in flow:

- **Cold Gas Efficiency:** This is the ratio of the heat contents calculated at room temperature of the syngas fuel output and the coal fuel input. The higher heating value is used here.
- **Temperature In:** This is the temperature of the oxidant stream into the gasifier.
- **Coal In:** This is the mass flow of coal into the gasifier on a wet-basis.
- **Water In:** This is additional mass flow of water added to the coal. (Wet coal already contains some water).
- Oxidant In: This is the mass flow of oxidant into the gasifier.
- **Sluice Water:** Slag collected can be removed from the gasifier and disposed by sluicing the slag with water.
- **Temperature Out:** This is the syngas temperature exiting the raw gas quench.
- **Pressure Out:** This is the approximate pressure of the syngas exiting the raw gas quench.
- **Syngas Out:**.This is the mass flow rate of syngas exiting the gasification but prior to the raw gas quench process.
- **Syngas Out:** This is the volumetric flow rate of syngas exiting the gasification but prior to the raw gas quench process.

**Wet Slag:**.Slag collected is removed from the gasifier. Sluice water may or may not be used to facilitate its transportation. This is the total slag flow rate leaving the gasifier on a wet basis.

### **Gasifier Oxidant Results**

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		Overall Plant Fuel	Ì.	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac <u>k</u>
				Maj	or Oxidant Con	Oxidant In (B-moles/hr)	Oxidant In (tons/hr)			
9	II		1	Nitrogen (N	12)		83.85	1.174	1	
d.	II		2	Oxygen (O2	2)		1.040e+04	166.5		
╢	II		3	Water Vapo	or (H2O)		0.0	0.0	-	
1	II		4	Carbon Dio	nide (CO2)		0.0	0.0	1	
	II		5	Carbon Mo	noxide (CO)		0.0	0.0	1	
11	II		6	Hydrochlor	uloric Acid (HCI)		0.0	0.0		
11	II		7	Sulfur Diox	ide (SO2)		0.0	0.0	]	
III	II		8	Sulfuric Ac	id (equivalent S	303)	0.0	0.0	]	
	II		9	Nitric Oxide	e (NO)		0.0	0.0		
	II		10	Nitrogen D	ioxide (NO2)		0.0	0.0		
	I		11	Ammonia (	NH3)		0.0	0.0		
	I		12	Argon (Ar)			463.7	9.262		
	I		13	Total			1.095e+04	176.9		
	I		14							
	I		15							
		Process Type: GE			~	]				
	I	<u>1</u> . Diagram	<u>2</u> . (	Dxidant	<u>3</u> . Synge	as <u>4</u> .C	apitalCost 🖌	<u>5</u> . O&M Cos	st <u>6</u> . Tota	al Cost

Gasifier – Gas Flow result screen.

Each result is described briefly below.

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

## **Gasifier Syngas Results**

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		Overall Plant	F <u>u</u> el	Ì	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac <u>k</u>							
3 X 1					Ма	jor Syngas Con	<b>ponents</b>	Syngas Out (B-moles/hr)	Syngas Out (tons/hr)									
3				1	Carbon Mo	noxide (CO)		1.583e+04	221.6									
91				2	Hydrogen	(H2)		1.430e+04	14.44									
				3	Methane (0	CH4)		231.1	1.853									
				4	Ethane (C2	H6)		0.0	0.0									
2				5	Propane (C	3H8)		0.0	0.0									
2111				6	Hydrogen	Sulfide (H2S)	ulfide (H2S)	Sulfide (H2S)	Sulfide (H2S)	Sulfide (H2S)	Sulfide (H2S)	iulfide (H2S)	ulfide (H2S)		234.0	3.987		
2				7	Carbonyl S	ulfide (COS)		11.64	0.3495									
-11				8	Ammonia (	NH3)		3.740	3.185e-02									
				9	Hydrochlor	ric Acid (HCI)		5.818	0.1061									
				10	Carbon Dic	uide (CO2)		6109	134.4									
				11	Water Vap	or (H2O)		4114	37.07	_								
				12	Nitrogen (P	12)		374.4	5.244	_								
				13	Argon (Ar)			359.9	7.189	_								
				14	Oxygen (O)	2)		0.0	0.0									
				15	Total			4.157e+04	426.3									
		Process Type:	GE			-												
		<u>1</u> . Diagram		<u>2</u> .0	Dxidant	<u>3</u> . Synge	as <u>4</u> .0	apitalCost 🖌	<u>5</u> . O&M Cos	st <u>6</u> . To	talCost							

Gasifier – Gas Flow result screen..

#### **Major Syngas Components**

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H₂):Total mass of hydrogen.

Methane (CH₄):Total mass of methane.

**Ethane** (C₂H₆):Total mass of ethane.

**Propane (C₃H₈):**Total mass of propane.

Hydrogen Sulfide (H₂S):Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH₃): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

**Carbon Dioxide (CO₂):** Total mass of carbon dioxide.

Water Vapor (H₂O): Total mass of water vapor.

Nitrogen (N₂): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O₂): Total mass of oxygen.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

### **Gasifier Capital Cost Results**

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*			GE	Gasifier Pro	cess Area Cost	s	Capital (MS	Cost		GE Gas	ifier Plant Costs	(	Capital Cost (M\$)
C.		1	CoalHa	ndling			34.7	9	1	Process Facilitie:	s Capital		174.6
121		2	Gasifica	tion			93.0	19	2	General Facilities	s Capital		26.19
		3	Low Te:	mperature Gas	s Cooling		33.4	2	3	Eng. & Home Of	fice Fees		17.46
	Ш	4	Process	Condensate	Treatment		13.3	11	4	Project Continge	ency Cost		26.19
$\rightarrow$	Ш	5	Process	Facilities Cap	oital		174	.6	5	Process Conting	ency Cost		21.37
91	Ш	6							6	Interest Charges	(AFUDC)		43.96
	Ш	7							7	Royalty Fees			0.8730
<u>~  </u>	Ш	8							8	Preproduction (S	Startup) Cost		10.67
	Ш	9							9	Inventory (Work	cing) Capital		2.658
	Ш	10							10	Total Capital Re	quirement (TCR)		324.0
	Ш	11							11				
	Ш	12							12				
		13							13				
	Ш	14							14				
		15							15	Effective TCR			324.0
		Pro	cess Ty	GE GE			~	]		Costs are in	Constant 2005 doll	ars.	
			<u>1</u> . Diagr	am /	<u>2</u> . Oxidant		<u>3</u> . Synge	15	<u>\</u> 4	CapitalCost /	<u>5</u> . O&M Cost	6.7	`otalCost

Gasifier Capital Cost results screen.

The **GE Gasifier Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

### **GE Gasifier Process Area Costs**

**Coal Handling:** This is the cost associated with the coal handling process area. Coal handling involves unloading coal from a train, storing the coal, moving the coal to the grinding mills, and feeding the gasifier with positive displacement pumps. A typical coal handling section contains one operating train and no spare train. A train consists of a bottom dump railroad car unloading hopper, vibrating feeders, conveyors, belt scale, magnetic separator, sampling system, deal coal storage, stacker, reclaimer, as well as some type of dust suppression system. Slurry preparation trains typically have one to five operating feeders, conveyors, belt scale, rod mills, storage tanks, and positive displacement pimps to feed the gasifiers. All of the equipment for both the coal handling and the slurry feed are commercially available. The direct cost model for the coal handling is based upon the overall flow to the plant rather than on a per train basis.

**Gasifier Area:** The GE gasification section of an IGCC plant contains gasifier, gas cooling, slag handling, and ash handling sections. For IGCC plants of 400 MW to 1100 MW, typically 4 to 8 operating gasification trains are used along with one spare train.

**Low Temperature Gas Cooling:** This is the cost associated with the Low Temperature Gas Cooling process area. The low temperature gas cooling section includes a series of three shell and tube exchangers.

The number of operating trains are estimated based on the total syngas mass flow rate and the range of syngas flow rates per train used.

- **Process Condensate Treatment:** The treated process condensate is used as make-up to the gas scrubbing unit, and because blowdown from the gas scrubbing unit is the larger of the flow streams entering the process condensate treatment section, it is expected that process condensate treatment cost will depend primarily on the scrubber blowdown flow rate.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

### **GE Gasifier Plant Costs**

Process Facilities Capital: (see definition above)

- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

**Effective TCR:** The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

### **Gasifier O&M Cost Results**

This screen is only available for the IGCC plant type.

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	0	Dve <u>r</u> a	11 Plant Fuel	Gasifier Area	<u>S</u> u Rem	lfur .oval	C <u>O</u> 2 Capture	Power <u>B</u> lock	B <u>y</u> -Prod. Mgmt	Stack		
			Variable (	Cost Component	0&M (M\$	( Cost //yr)		Fixed	Cost Component		O&M Cost (M\$/yr)	
		1	Coal		33	.87	1	Operating Labor			2.009	
11		2	Oil		1.7	77	2	Maintenance La	bor		3.959	
11		3	Other Fuels		4.331	e-02	3	Maintenance Ma	aterial		5.938	
111		4	Misc. Chemicals		0	.0	4	Admin. & Suppo	ort Labor		1.791	
Ш		5	Electricity		2.3	.39	5	Total Fixed Cost	s		13.70	
11		6	Water		0.4	464	6					
Ш		7	Slag Disposal		1.5	11	7					
1		8	Total Variable Cos	its	39	99	8					
Ш		9					9					
Ш		10					10					
		11					11					
Ш		12					12					
Ш		14					14					
Ш		15					15	Total O&M Cos	ts		53,69	
		Pro	cess Type: GE			-		Costs are in	Constant 2005 d	ollars.		
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Gasifier – O&M Cost results screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

### Variable Cost Component

**Coal:** This is the annual cost of the coal used by the gasifier.

- **Oil:** This is the annual cost of the oil consumed by the gasifier.
- **Other Fuels:** This is the annual cost of any other fuels used by the gasifier.
- **Misc. Chemicals:** This is the annual cost of the miscellaneous chemicals used by the gasifier.
- **Electricity:** The cost of electricity consumed by the processes in the gasifier area..
- Water: This is the annual cost of the water used by the gasifier.
- **Slag Disposal:** This is the solid disposal cost per year for the GE entrained-flow reactor.
- **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.
### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- **Admin. & Support Labor:** The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

# **Gasifier Total Cost Results**

This screen is only available for the IGCC plant type.

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*				Cost	Component		M\$/yr	\$/MWh	Percent Total	
			1	Annual Fixed Cost			13.70	3.875	13.48	
P			2	Annual Variable C	ost		39.99	11.31	39.35	
			3	Total Annual O&N	A Cost		53.69	15.19	52.82	
			4	Annualized Capita	lCost		47.95 13.		47.18	
			5	Total Levelized Ar	mual Cost		101.6	28.75	100.0	
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Gasifier – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Gasifier Unit**.

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

#### **Cost Component**

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# **Air Preheater**

The <u>Air Preheater</u> Technology Navigation Tab in the <u>Get Results</u> program area contains result screens that display the flow rates and temperatures of substances through the air preheater. This is only available in the Combustion (Boiler) plant type.

# Air Preheater Diagram

This screen is only available for the Combustion (Boiler) plant type.



Air Preheater - Diagram.

The **Diagram** result screen displays an icon for the Air Preheater and values for major flows in and out of it. Each result is described briefly below in flow order (not from top to bottom and left to right as they display on the screen).

#### **Recycled Flue Gas Entering Preheater**

Flue gas can be recycled back into the boiler when an  $O_2$ - $CO_2$  Recycle configuration is specified in **Configure Plant**. This is more commonly known as an "oxyfuel" configuration. Flue gas is not recycled in any other configuration.

**Recycled Flue Gas Temp:** Temperature of the recycled flue gas entering the induced-draft fan.

**Recycled Flue Gas:** Volumetric flow rate of the recycled flue gas entering the induced-draft fan.

#### **Atmospheric Air Entering Preheater**

Ambient Air Temp: Temperature of the atmospheric air entering the induced-draft fan.

**Ambient Air:** Volumetric flow rate of air entering the induced-draft fan, based on the atmospheric air temperature and atmospheric pressure.

#### **Heated Air Exiting Preheater**

**Heated Oxidant Temp:** Heated combustion air or recycled flue gas temperature exiting the air preheater. This is a complicated function of the heat content and temperatures of the flue gas.

**Heated Oxidant:** Volumetric flow rate of the combustion air or recycled flue gas exiting the air preheater, based on the combustion air temperature and atmospheric pressure.

#### Leakage Air

**Leakage Air Temp:** Temperature of the atmospheric air leaking across the air preheater into the flue gas. This is determined by the leakage parameter on the base plant performance input screen.

**Leakage Air:** Volumetric flow rate of the atmospheric air leaking across the air preheater into the flue gas. This is based on the leakage temperature and atmospheric pressure.

#### Flue Gas Entering Preheater

**Temperature In:** Temperature of the flue gas entering the air preheater. This is determined by the flue gas outlet temperature of the module upstream of the air preheater (e.g., the boiler economizer).

- **Flue Gas In:** Volumetric flow rate of the flue gas entering the air preheater, based on the flue gas inlet temperature and atmospheric pressure.
- **Fly Ash In:** Total solids mass flow rate in the flue gas entering the air preheater. This is determined by the solids exiting the module upstream of the air preheater (e.g., the boiler economizer).

**Mercury In:** Total mass of mercury entering the air preheater in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

#### Air Preheater Performance

**SO3 Removal:** Percent of the SO₃ removed from the flue gas.

#### **Cooled Flue Gas Exiting Preheater**

**Temperature Out:** Temperature of the flue gas exiting the air preheater. This is determined by the parameter on the base plant performance input screen.

**Flue Gas Out:** Volumetric flow rate of the flue gas exiting the air preheater, based on the flue gas exit temperature and atmospheric pressure.

- **Fly Ash Out:** Total solids mass flow rate in the flue gas exiting the air preheater. This is a function of the percent ash entering the flue gas (furnace emissions input parameter) and the ash content of the fuel.
- **Mercury Out:** Total mass of mercury exiting the air preheater in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

# **Air Preheater Flue Gas Results**

This screen is only available for the **Combustion (Boiler)** plant type.

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0			Configure Plant	Set <u>P</u> ara	meters	Ĭ	<u>G</u> et Re	esults
		Overall Plant	Fuel Boiler Air I Preheater Co	MOx Mercu	ny <u>T</u> SP Control	<u>S</u> O2 Control	C <u>O</u> 2 Capture I	g-Prod. Mgmt Stac <u>k</u>
			Major Flue Gas Components	Flue Gas In (lb-moles/hr)	Air Leak (B-moles/hr)	Flue Gas Out (B-moles/hr)	Flue Gas In (tons/hr)	Air Leak (tons/hr)
8		1	Nitrogen (N2)	1.083e+05	1.711e+04	1.254e+05	1516	239.7
91		2	Oxygen (O2)	4814	4591	9405	77.02	73.46
		3	Water Vapor (H2O)	1.342e+04	631.4	1.405e+04	120.9	5.689
3		4	Carbon Dioxide (CO2)	2.049e+04	0.0	2.049e+04	450.8	0.0
		5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0
211		6	Hydrochloric Acid (HCl)	5.640	0.0	5.640	0.1028	0.0
2		7	Sulfur Dioxide (SO2)	212.9	0.0	212.9	6.820	0.0
-		8	Sulfuric Acid (equivalent SO3)	2.933	0.0	1.467	0.1174	0.0
		9	Nitric Oxide (NO)	10.98	0.0	10.98	0.1648	0.0
		10	Nitrogen Dioxide (NO2)	0.5781	0.0	0.5781	1.330e-02	0.0
		11 Ammonia (NH3)		0.2962	0.0	0.2962	2.522e-03	0.0
		12	Argon (Ar)	1292	204.6	1497	25.82	4.087
		13	Total	1.485e+05	2.254e+04	1.710e+05	2198	322.9
		14						
		15 I Proce	ss Type: Air Preheater	<b>T</b>				Þ
		1.	Diagram <u>2</u> . Flue Gas <u>3</u> .	Oxidant /				

Air Preheater – Flue Gas result screen.

### **Major Flue Gas Components**

The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the air preheater. For each component entering and exiting in flue gas, values are given in both moles and mass per hour. For each component entering in atmospheric air, values are given in moles per hour. Each result is described briefly below.

Nitrogen (N2): Total mass of nitrogen.

Oxygen (O2): Total mass of oxygen.

Water Vapor (H2O): Total mass of water vapor.

Carbon Dioxide (CO2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.

Ammonia (NH3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

## **Air Preheater Oxidant Results**

This screen is only available for the Combustion (Boiler) plant type.

		Configure Plant	Set Para	meters		Get Re	esults	
O. F	ve <u>r</u> all Plant	Fuel Boiler Air Preheater	<u>N</u> Ox Control <u>M</u> ercu	uy <u>T</u> SP Control	SO2 Control	CO2 Capture	g-Prod. Mgmt Stac <u>k</u>	
		Major Air Components	Oxidant In (Ib-moles/hr)	Recycle In (lb-moles/hr)	Oxidant Out (B-moles/hr)	Oxidant In (tons/hr)	Recycle In (tons/hr)	
	1	Nitrogen (N2)	1.081e+05	0.0	1.081e+05	1514	0.0	
	2	Oxygen (O2)	2.900e+04	0.0	2.900e+04	464.0	0.0	
	3	Water Vapor (H2O)	3988	0.0	3988	35.93	0.0	
	4	Carbon Dioxide (CO2)	0.0	0.0	0.0	0.0	0.0	
	5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0	
	6	Hydrochloric Acid (HCl)	0.0	0.0	0.0	0.0	0.0	
	7	Sulfur Dioxide (SO2)	0.0	0.0	0.0	0.0	0.0	
	8	Sulfuric Acid (equivalent SO3)	0.0	0.0	0.0	0.0	0.0	
	9	Nitric Oxide (NO)	0.0	0.0	0.0	0.0	0.0	
	10	Nitrogen Dioxide (NO2)	0.0	0.0	0.0	0.0	0.0	
	11	Ammonia (NH3)	0.0	0.0	0.0	0.0	0.0	
	12	Argon (Ar)	1292	0.0	1292	25.82	0.0	
	13	Total	1.424e+05	0.0	1.424e+05	2039	0.0	
	14							
	15							
							•	

Air Preheater – Flue Gas result screen.

### **Oxidant Gas Components**

The **Oxidant** result screen displays a table of quantities of air or recycled flue gas components entering and exiting the air preheater. For each component entering and exiting in flue gas, values are given in both moles and mass per hour. For each component entering in atmospheric air, values are given in moles per hour. Each result is described briefly below.

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O2): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **In-Furnace Controls**

The **<u>NOx</u>** Control Technology Navigation Tab contains screens that address combustion or post-combustion air pollution technologies for Nitrogen Oxides.

These screens are available if the In-Furnace Controls for the **Combustion** (**Boiler**) plant type configurations have been selected for  $NO_x$  control under Combustion Controls. If you have selected both In-Furnace Controls and a Hot-Side SCR for  $NO_x$  control, you may switch between the two sets of screens that configure these technologies by using the Process Type pull-down menu at the bottom of the screen



The Process Type pull-down menu

# **In-Furnace Controls Configuration**

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for configuring the  $NO_x$  Control technology are entered on the **Config** input screen. Each parameter is described briefly below.

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51		<u>(</u>	Configure	Plant	Ì	Set	<u>P</u> aram	iete	ers	Ĩ	<u>(</u>	Get Res	sults	
- -	O' F	ve <u>r</u> all Plant	Fuel	Base Plant	Mercu	y <u>N</u> C Cont	x xol	<u>T</u> S Con	SP <u>S</u> ttrol Co	,O2 ntrol	C <u>O</u> 2 Capture	By-Pi Mg	nd. mt St	ac <u>k</u>
3				Title		Units	τ	Jnc	Value	Calc	Min	Max	Default	
,		1	In-Furnace	Controls					LNB & SI-		Menu	Menu	NB & SNCI	
5		2						_						
		3	SNCR Reag	ent Type				_	Urea 💌		Menu	Menu	Urea	
a II		4						_						
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		Proce	ess Type:	In-Furnace C	ontrols		-		_					
	$\mathbf{\Gamma}$	<u>1</u> . C	onfig	2. Performan	se 🖌 🛔	3. Capital Co	st /	4.	O&M Cost					

In – Furnace Controls – Config input screen.

#### In – Furnace Controls

This pull-down menu chooses what type of in-furnace  $NO_x$  controls are used. These technologies reduce  $NO_x$  between the primary fuel injection into the furnace and the economizer. These can be used in the combinations given in addition to the SCR. The low  $NO_x$  burner options are not displayed when a cyclone boiler is configured. The full list of choices is:

- **LNB** Low NO_x burners are a combustion NO_x control. These burners replace the upper coal nozzle of the standard two-nozzle cell burner with a secondary air port. The lower burner coal nozzle is enlarged to the same fuel input capacity as the two standard coal nozzles. The LNB operates on the principle of staged combustion to reduce NO_x emissions. Approximately 70% of the total air (primary, secondary, and excess air) is supplied through or around the coal-feed nozzle. The remainder of the air is directed to the upper port of each cell to complete the combustion process. The fuel-bound nitrogen compounds are converted to nitrogen gas, and the reduced flame temperature minimizes the formation of thermal NO_x. The net effect of this technology is greater than 50% reduction in NO_x formation with no boiler pressure part changes and no impact on boiler operation or performance. Low NO_x burners are not available for cyclone boilers.
- **LNB & OFA** Low NO_x burners (see above) with overfire air is another combustion NO_x reduction method. Overfire air is an enhancement to LNB to reduce NO_x formation by further separating the air injection locations. An addition of approximately 10% NO_x is reduced by the addition of OFA. A portion of the secondary air used by LNB is diverted to injection ports located above the primary combustion zone, reducing available oxygen in the primary combustion zone. Overfire air in the IECM refers to separated OFA for both wall and tangential-fired boilers. This option is not supported for cyclone boilers.

- **Gas Reburn** Gas reburn is a post-combustion  $NO_x$  reduction method. Gas reburn substitutes up to one-fourth of the heat input of coal with natural gas, reducing the  $NO_x$  up to 60% as a function of the amount of reburn. The natural gas is injected above the primary combustion zone to create a reducing zone. Reburn has been shown to be effective for wall and tangential-fired boilers and more recently for cyclone boilers.
- **SNCR** Selective non-catalytic reduction is a post-combustion  $NO_x$  reduction method. This process removes  $NO_x$  from flue gas by injecting one of two nitrogen-based reagents, ammonia or urea, in the presence of oxygen to form nitrogen and water vapor. Optimum removal is achieved in a temperature window of 1600-2000 F. Although the technology is very simple, the narrow temperature window provides the primary challenge. Ammonia slip and ash contamination are additional concerns that must be considered with SNCR.
- **LNB & SNCR** Low  $NO_x$  burners can be used in conjunction with SNCR to achieve very high  $NO_x$  removals. Both technologies are described in detail above.

If a Tangential or Wall Furnace Type have been selected in **<u>Configure Plant</u>**, then all five options will display. If you have selected a Cyclone Furnace type, then only **Gas Reburn** and **SNCR** will display.

The default for Tangential and Wall furnaces is **LNB & SNCR**. The default for a Cyclone furnace is **Gas Reburn**.

#### SNCR Reagent Type

Only displayed when **SNCR** or **LNB & SNCR** have been selected in the In-Furnace Controls pull-down menu. Nitrogen-based reagent injection is used in an SNCR to reduce  $NO_x$  in the presence of oxygen to form nitrogen and water vapor. The reagent choices are:

- $Urea Urea (CO(NH_2)_2)$  is typically diluted to a 15-20% concentration with water. Urea has the advantage of safety and ease of storage and handling. Urea is the default reagent used in the IECM.
- $\begin{array}{l} \mbox{Ammonia} {\rm Ammonia}\ {\rm can}\ {\rm be}\ {\rm supplied}\ {\rm in}\ {\rm two}\ {\rm forms:}\ {\rm anhydrous}\ ({\rm NH_3})\ {\rm and}\ {\rm aqueous}({\rm NH_4OH}). \ {\rm The}\ {\rm IECM}\ {\rm considers}\ {\rm only}\ {\rm anhydrous}\ {\rm ammonia}. \ {\rm Ammonia}\ {\rm may}\ {\rm be}\ {\rm an}\ {\rm advantage}\ {\rm when}\ {\rm using}\ {\rm an}\ {\rm SNCR}\ {\rm in}\ {\rm conjunction}\ {\rm with}\ {\rm an}\ {\rm SCR}\ {\rm system}. \end{array}$

## **In-Furnace Controls Performance Input**

(		(	Configure I	Plant	T	Set	Param	iete	rs	Ť		Get Res	ults	
ſ	Ove <u>r</u> a Plan	-11 t	Fuel	Base Plant	<u>M</u> ercu	ry <u>N</u> Ox Contr	o1 (	<u>T</u> S Con	P <u>S</u> trol Cor	D2 ntro1	C <u>O</u> 2 Capture	By-Pr Mgr	od. nt St	ac <u>k</u>
	Γ			Title		Units	U	Inc	Value	Calc	Min	Max	Default	
I	Ī	1	Combust	ion NOx Contr	<u>ols</u>									
		2	Actual NOx R	emoval Efficie	ncy	%			31.34		0.0	80.00	calc	
	Ē	3	Maximum NO:	x Removal Effi	ciency	%			50.00		0.0	100.0	calc	
	Ē	4												
	Ī	5												
	Ī	6	SNCF	R NOx Control										
		7	Actual NOx R	emoval Efficie:	ncy	%			38.00		0.0	60.00	calc	
	Ī	8	Maximum NO:	x Removal Effi	ciency	%			38.00		0.0	100.0	calc	
II		9	Urea Concent	ration Injected	L	wt %			20.00		0.0	100.0	20.00	
		10	SNCR Power I	Requirement		% MWg	3		1.000e-02	V	0.0	10.00	calc	
		11												
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*In – Furnace Controls – Performance input screen.* 

Inputs for the performance of the **In-Furnace Controls**  $NO_x$  control technology are entered on the on the **Performance** input screen. Combustion NOx Controls These inputs will display if any combustion technology is used in the option selected in the **In-Furnace Controls** pull-down menu. This includes the **LNB**, **LNB** + **OFA**, **Gas Reburn**, and the **LNB** + **SNCR** options.

## **Combustion NO_x Controls**

- Actual NOx Removal Efficiency: This is the NO_x removal efficiency of the LNB, LNB + OFA, and Gas Reburn options, and the LNB removal portion of the LNB + SNCR option. The percent reduction of NO_x is calculated by comparing the actual NO_x emission to the uncontrolled NO_x emission. The removal is a function of the **In-Furnace Control** type selected in the pull-down menu, the boiler type, and the maximum removal efficiency (below). Note: that the removal is not a function of the NO_x emission constraint. This input is highlighted in blue.
- **Maximum NOx Removal Efficiency:** The maximum removal efficiency of  $NO_x$  sets the upper bound for the actual  $NO_x$  removal efficiency (above). The maximum removal is a function of the In-Furnace control type and the boiler type.
- **Natural Gas Heat Input:** This input will only display if **Gas Reburn** is selected in the **In-Furnace Controls** pull-down menu. The flow rate of natural gas injected is determined by this input on a Btu heat input basis.

## **SNCR NO_x Control**

These inputs will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu.

- Actual NOx Removal Efficiency: The actual  $NO_x$  removal efficiency is a function of the maximum  $NO_x$  removal efficiency (below) and the  $NO_x$  emission constraint. This input is highlighted in blue.
- **Maximum NOx Removal Efficiency:** The maximum removal efficiency is calculated as a function of the gross electrical output. Because of difficulty mixing the reagent in the flue gas for larger boilers, the maximum efficiency decreases with increasing plant size.
- **Urea Concentration Injected:** Urea is typically injected as a liquid diluted by water. This parameter defines the amount of water used to dilute the urea prior to injection.
- **SNCR Power Requirement:** As mentioned above, the power requirement for the SNCR is a function of gross electrical output of the power plant. The value is determined by the need for tank heaters when urea reagent is used.

# **In-Furnace Controls Capital Cost**

This screen is only available for the Combustion (Boiler) plant type. Unlike most capital cost input screens, these technologies costs are provided as total capital costs on an energy input basis.

Untit	ed*					-			
	<u>(</u>	Configure Plant	Set <u>P</u> ar	amete	rs			Get Res	sults
Ove <u>r</u> Plar	all t	Fuel Base Plant Merc	ury <u>N</u> Ox Control	<u>T</u> S Con	P S trol Co	5O2 ontro1	C <u>O</u> 2 Capture	By-Pr Mg	nod. mt Stac
ſ		Title	Units	Unc	Value	Calc	Min	Max	Default
	1	Base Capital Costs	]						
	2	(excluding retrofit; using gross kW)							
	3	Combustion Modifications	\$/kw-gross		8.913		0.0	30.00	calc
	4	SNCR Boiler Modifications	\$/kw-gross		6.927		0.0	15.00	calc
	5								
	6	Retrofit Capital Cost Factors							
	7	Combustion Modifications	retro \$/new \$		1.500		0.0	5.000	1.500
	8	SNCR Boiler Modifications	retro \$/new \$		1.400		0.0	5.000	1.400
	9								
	10	<u>Total Capital Costs</u>							
	11	(including retrofit; using gross kW)							
	12	Combustion Modifications	\$/kw-gross		13.37		0.0	40.00	calc
	13	SNCR Boiler Modifications	\$/kw-gross		9.698		0.0	20.00	calc
	14								
	15								
	16								
	17								
	18	TCR Recovery Factor	%		100.0		0.0	100.0	100.0
F	roc	ess Type: In-Furnace Controls	•		Costs are	e in Con	stant 2005	dollars.	

In-Furnace Controls – Capital Cost input screen.

The **Combustion Modifications** inputs will not display if **SNCR** is selected in the In-Furnace Controls pull-down menu. The **SNCR Boiler Modifications** inputs will only display if **SNCR** or **LNB & SNCR** is selected

## **Base Capital Costs**

The base capital costs (excluding retrofit, using gross KW) specify the total base capital costs, not considering any retrofit factors. No detailed information about

direct or indirect costs is given. The costs are given as a total in units of dollars per gross kilowatt.

- Combustion Modifications: This is the base capital cost of the LNB, LNB + OFA, and Gas Reburn options, and the LNB removal portion of the LNB + SNCR option. This parameter is not shown when one of these options is not selected.
- **SNCR Boiler Modifications:** This specifies the total base capital cost for the **SNCR** boiler  $NO_x$  removal equipment alone. This parameter is not shown when one of the SNCR options is not selected.

### **Retrofit Capital Cost Factors**

Retrofit cost factors allow you to differentiate between the base cost of purchasing the capital equipment and the actual cost incurred. These factors vary from unit to unit.

- Combustion Modifications: This is the retrofit cost factor for the LNB, LNB + OFA, and Gas Reburn options, and the LNB removal portion of the LNB + SNCR option. This parameter is not shown when one of these options is not selected
- **SNCR Boiler Modifications:** This is the retrofit cost factor for the **SNCR** option alone. This parameter is not shown when one of the SNCR options is not selected

## **Total Capital Costs:**

- Combustion Modifications: This is the total capital cost of the LNB, LNB + OFA, and Gas Reburn options, and the LNB removal portion of the LNB + SNCR option. This combines the base capital cost with the retrofit cost factor. This parameter is not shown when one of these options is not selected.
- **SNCR Boiler Modifications:** This specifies the total capital cost for the **SNCR** boiler  $NO_x$  removal equipment alone. This parameter is not shown when one of the SNCR options is not selected
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for in-furnace controls that has been paid off.

## In-Furnace Controls O&M Cost

		Configure .	Plant	T	Set Par	ramete	rs	T		Get Res	alts
Ov P:	· rerall lant	Fuel	<u>B</u> ase Plant	<u>M</u> ercury	NOx Control	TS Con	SP trol Co	02 01101	C <u>O</u> 2 Capture	By-Pr Mg	od. mt Stac
			Title	[	Units	Unc	Value	Calc	Min	Max	Default
	1	Variat	ole O&M Costs								
	2	UreaCost			\$/ton		412.4		200.0	400.0	calc
	3	Ammonia Co	st		\$/ton		248.2		100.0	400.0	calc
	4										
	5	Electricity Pri	ce (Base Plant)		\$/MWh		41.12		0.0	200.0	calc
	6										
	7	Fixe	d O&M Cost								
	8	Combustion	Modifications		%TPC		1.500		0.0	5.000	1.500
	9	SNCR Boiler	Modifications		%TPC		1.500		0.0	5.000	1.500
	10										
	11										
	12					_					
	13										
	14										
	15										
	10										<u> </u>
	18										
	10	-									

In-Furnace Controls – O&M Cost input screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below.

#### Variable O&M Costs

- **Urea Cost:** This is the cost of urea used for any of the SNCR options. This input will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu
- **Ammonia Cost:** This is the cost of ammonia used for any of the SNCR options. This input will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu
- Natural Gas Cost: This is the cost of natural gas used for the Gas Reburn option. This input will only display if Gas Reburn is selected
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as combustion boiler and an air preheater.

### Fixed O&M Cost

Fixed O&M costs are given as a total cost, rather than itemized costs broken down by individual maintenance and labor costs. The results are given as a percent of the total capital cost.

**Combustion Modifications:** This is the total fixed operating and maintenance cost for boiler  $NO_x$  modifications made in the combustion zone (LNB, OFA, natural gas reburn). This parameter is not shown if one of these options is not selected.

**SNCR Boiler ModificationsVariable O&M Costs:** This is the total fixed O&M cost for the **SNCR** equipment alone. This input is not shown if one of the SNCR options is not selected.

## **In-Furnace Controls Diagram**

This screen is only available for the Combustion (Boiler) plant type.



In-Furnace Controls – Diagram

The **Diagram** result screen displays an icon for the **In-Furnace Controls**  $NO_x$  technology selected and values for major flows in and out of it.

## **Fuel Entering Boiler**

- **Wet Coal In:** Fuel flow rate into the boiler on a wet basis. Waste products removed prior to the burners are not considered here.
- **Mercury In:** This is the mass flow rate of total mercury entering the boiler. The mass reflects the molecular weight of elemental mercury.

## **Air Entering Boiler**

- **Temperature:** Heated air temperature measured at the burners. This is generally determined by the combustion air temperature exiting the air preheater.
- **Heated Air:** Volumetric flow rate of the air at the burners, based on the air temperature at the burners and atmospheric pressure.

#### Flue Gas Exiting Convective Zone

This the area of the furnace between the combustion zone and the SNCR (if present). Changes in the flue gas after combustion due to in-furnace combustion  $NO_x$  controls are reflected here.

**Temperature:** Temperature of the flue gas exiting the convective zone.

- **Flue Gas:** Volumetric flow rate of the flue gas exiting the convective zone, based on the temperature exiting the convective zone and atmospheric pressure.
- **Fly Ash:** Total solids mass flow rate in the flue gas exiting the convective zone. This includes ash, unburned carbon and unburned sulfur.
- **Mercury:** Total mass of mercury in the flue gas exiting the convective zone. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

### Flue Gas Exiting the Economizer

- **Temperature Out:** Temperature of the flue gas at the exit of the economizer.
- **Flue Gas Out:** Volumetric flow rate of the flue gas at the exit of the economizer, based on the temperature at the exit of the economizer and atmospheric pressure.
- **Fly Ash Out:** Total solids mass flow rate in the flue gas at the exit of the economizer. This includes ash, unburned carbon and unburned sulfur.
- **Mercury Out:** Total mass of mercury in the flue gas exiting the economizer. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

#### **Gas Reburn**

**Reburn Gas**: This is the flow rate of natural gas into the boiler. This result will only display if **Gas Reburn** is selected in the In-Furnace Controls pull-down menu

### SNCR

The SNCR is located in the upper portion of the boiler. Several parameters are reported as a summary. These results will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu in the **Set Inputs** part of the interface.

- **Stoic.:** This is the actual reagent stoichiometry used in the SNCR. Note that urea has double the moles of nitrogen relative to that of ammonia.
- **SNCR Reagent:** This is the mass flow rate of reagent (urea or ammonia) injected by the SNCR into the boiler. Note that water used to dilute the urea is included in this flow rate.

## NO_x Removal Performance

**Boiler NOx Removal:** This is the composite removal efficiency of the boiler  $NO_x$  technologies associated with low  $NO_x$  burners, overfire air,

and reburn. It does not include the removal efficiency of an SNCR system.

**SNCR NOx Removal:** This is the removal efficiency of the SNCR system alone. It does not take into consideration any other NO_x reduction prior to the SNCR.

# **In-Furnace Controls Flue Gas Results**

This screen is only available for the Combustion (Boiler) plant type.

<b>V IEC</b> File J	CN Ec	<mark>l Interf</mark> a lit <u>V</u> iew	i <b>ce</b> Go <u>W</u> indow <u>H</u> elp											
ъſ	5	Untitle	ed*											
۶II	ſ		<u>C</u> onfigure Plan	t	Ĩ	Set <u>P</u> ara	meters	Ì	<u>G</u> et R	esults				
	ſ	Ove <u>r</u> al Plant	I Fuel Boil	er <u>A</u> ir Prehes	ater Co	1Ox ontrol Mercu	uy <u>T</u> SP Control	Control	C <u>O</u> 2 B Capture	y-Prod. Mgmt Stac <u>k</u>				
			Major Flue Ga	ь Сонронен	its	Combustion Zone In (B-moles/hr)	Combustion Zone Out (Ib-moles/hr)	Convective Zone Out (Ib-moles/hr)	Combustion Zone In (tons/hr)	Combustion Zone Out (tons/hr)				
-11		1	Nitrogen (N2)			1.082e+05	1.082e+05	1.083e+05	1516	1516				
ज्ञा ।		2	Oxygen (O2)			4810	4819	4816	76.97	77.11				
╢		3	Water Vapor (H2O)			1.297e+04	1.297e+04	1.298e+04	116.9	116.9				
		4	<ul> <li>4 Carbon Dioxide (CO2)</li> <li>5 Carbon Monoxide (CO)</li> <li>6 Hydrochloric Acid (HCl)</li> </ul>			2.048e+04	2.048e+04	2.049e+04	450.7	450.7				
		5				0.0	0.0	0.0	0.0	0.0				
1		6				5.640	5.640	5.640	0.1028	0.1028				
		7	Sulfur Dioxide (SO2)	alfur Dioxide (SO2)		214.1	214.1	214.1	6.859	6.859				
ᅫ		8	Sulfuric Acid (equiva	lent SO3)		1.727	1.727	1.727	6.913e-02	6.913e-02				
		9	Nitric Oxide (NO)			51.61	35.43	21.97	0.7744	0.5316				
		10	Nitrogen Dioxide (NC	12)		2.716	1.865	1.156	6.249e-02	4.290e-02				
		11	Ammonia (NH3)	onia (NH3) n (Ar)		0.0	0.0	2.600	0.0	0.0				
		12	Argon (Ar)			on (Ar)		gon (Ar)				1292	1292	1292
		13	Total			1.481e+05	1.481e+05	1.481e+05	2194	2194				
		14												
		15 <u> </u> Proc	ess Type: In-Furna	ce Controls	;			1		Þ				
	Į	1	Diagram <u>2.1</u>	Flue Gas	<u>3</u> .C	apitalCost /	<u>4</u> . O&M Cos	st <u>5</u> . To	talCost /					

In-Furnace Controls – Flue Gas result screen.

The **Flue Gas** result screen for **In-Furnace Controls** displays a table of quantities of gas components entering and exiting the combustion zone. For each component, quantities are given in both moles and mass per hour. It also displays quantities of gas components exiting the convective zone in moles per hour. Each result is described briefly below.

#### **Major Flue Gas Components**

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **In-Furnace Controls Capital Cost Results**

This screen is only available for the Combustion (Boiler) plant type.

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õ			<u>C</u> onfig	gure Plai	ıt	1	Set	Para	ame	ters	<u>G</u> e	t Results	
		Ove <u>r</u> a Plan	all F⊡e	el <u>B</u> o:	iler <u>A</u> i Prehe	ater (	<u>N</u> Ox Control	Mero	cury	<u>T</u> SP Control Co	202 CO2 ontrol Capture	By-Prod. Mgmt	Stac <u>k</u>
×			Combusti	ion NOx Pr	ocess Area (	osts	Capital C (M\$)	ost		Combustia	n NOx Plant Costs	capita (M	l Cost (\$)
B		1							1	Combustion NOx	Capital Requireme	nt 8.7	14
P		2							2	SNCR Capital Re	quirement	6.3	21
		3						_	3	Total Capital Rec	uirement (TCR)	15.	<mark>03</mark>
		4						-	4				
		5						_	5				
8		7						-	7				
<u></u> ?		8						_	8				
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		Proc	cess Type:	In-Furna	nce Control	5	•		15	Costs are in (	Constant 2005 doll:	ars.	<u>.</u>
			L. Diagram	<u> </u>	Flue Gas	<u>λ</u> _3.	Capital Co	st	4	.O&MCost	<u>5</u> . Total Cost		

In-Furnace Controls – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the **In-Furnace Controls**  $NO_x$  control technology. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen.

#### **Total Capital Costs**

- **Combustion NOx Capital Requirement:** The total capital costs, including retrofit costs, for the LNB, OFA, and gas reburn technologies are included here. A zero is displayed when none of these technologies are installed.
- **SNCR Capital Requirement:** The total capital costs, including retrofit costs, for the SNCR technology is included here. A zero is displayed when an SNCR is not installed.

Total Capital Requirement: Sum of the above.

**Effective TCR:** The TCR of the retrofit  $NO_x$  controls that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the hot-side SCR.

## In-Furnace Controls O&M Cost Results

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			<u>C</u> onfigure Plant	Set <u>P</u> ar	ame	ters <u>G</u> et Res	ults
		Over Plar	all Fuel Eoiler Air tt Fuel Eoiler Preheater (	NOx Control Merc	ury	TSP         SO2         CQ2         By-F           Control         Control         Capture         Mg	rod. gmt Stac <u>k</u>
*			Variable Cost Component	O&M Cost (M\$/yr)		Fixed Cost Component	O&M Cost (M\$/yr)
		1	Fuel	0.0	1	Combustion NOx Costs	0.1307
P		2	Reagent	3.417	2	SNCR Boiler Costs	9.481e-02
		3	Water	8.608e-03	3	Total Fixed Costs	0.2255
		4	Electricity	1.352e-02	4		
		5	Total Variable Costs	3.440	5		
8		6			6		
N?		7			7		
		8			8		
		y 10			10		
		11			11		
		12			12		
		13			13		
		14			14		
		15			15	Total O&M Costs	3.665
		Pro	cess Type: In-Furnace Controls	•		Costs are in Constant 2005 dollars.	
			1. Diagram / 2. Flue Gas / 3.	Capital Cost 🖌	4	. O&M Cost <u>5</u> . Total Cost /	

This screen is only available for the Combustion (Boiler) plant type.

In-Furnace Controls- O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **In-Furnace Controls**  $NO_x$  control technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

#### **Variable Cost Components**

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

- **Fuel:** The total fuel costs associated with gas reburn are included here.
- **Reagent:** The total reagent costs (urea and ammonia) used for the SNCR system are included here.
- Water: This is the cost of the water used to dilute the urea for the SNCR.
- **Power:** This is the power used for the pumps to move reagents and water in the SNCR.
- **Total Variable Costs:** This is the sum of the entire variable O&M costs listed above. This result is highlighted in yellow.

#### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Combustion NOx Costs:** This is the fixed O&M costs associated with the LNB, OFA, and gas reburn systems.
- **SNCR Boiler Costs:** This is the fixed O&M costs associated with the SNCR system.

**Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

**Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

## **In-Furnace Controls Total Cost Results**

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6		<u>C</u> onfigure	Plant	Ĩ	Set	t <u>P</u> aramete	rs	Ĩ	Get Results	1
	Ove <u>r</u> all Plant	Fuel	<u>B</u> oiler	<u>A</u> ir Preheater	<u>N</u> Ox Control	Mercury	TSP Control C	<u>S</u> O2 C ontrol Cap	02 By-Prod. oture Mgmt	Stac <u>k</u>
*			Cost	Сонфоненt		M\$/yr	\$/MWh	\$/ton equi NO2 remov	v. red Percent Total	
E		1 Annual	Fixed Cost	4		0.2255	0.1031	47.79	3.829	
		3 Total A	nnual O&I	OSI A Cost		3.440	1.675	728.9	62.22	
-		4 Annual	ized Capita	1Cost		2.225	1.017	471.5	37.78	
		6	evenzed At	mual Cost		5.890	2.693	1248	100.0	
* •?		7								
		8								
		10								
		11								
		13								
		14								
	Process	Type: In-F	⁻ urnace C	ontrols	•		Costs are in	Constant 200	5 dollars.	
	<u>1</u> , Di	iagram /	<u>2</u> . Flue	Gas 🖌	<u>3</u> . Capital C	ost <u>(</u> <u>4</u> .C	&M Cost	<u>5</u> . Total C	ost	

This screen is only available for the Combustion (Boiler) plant type.

In-Furnace Controls – Total Cost result screen

#### **Cost Component**

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **In-Furnace Controls**  $NO_x$  Control technology. These costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below. Note that all costs expressed in \$\frac{1}{100} NO_2\$ removed assume tons of equivalent  $NO_2$ .

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# Hot-Side SCR

The <u>NOx Control</u> Technology Navigation Tab contains screens that address combustion or post-combustion air pollution technologies for Nitrogen Oxides in the **Combustion (Boiler)** plant type configurations.

If you have selected a Hot-Side SCR, there will be six input screens and therefore six Input Navigation Tabs. If you have selected In-Furnace Controls, there will be four input screens and therefore four Input Navigation Tabs.

These input screens are only available if a Hot-Side SCR has been selected under Post-Combustion Controls in the **Configure Plant** program area.

If you have selected both In-Furnace Controls and a Hot-Side SCR for  $NO_x$  control, you may switch between the two sets of screens that configure these technologies by using the Process Type pull-down menu at the bottom of the screen.



The Process Type pull-down menu

# **Hot-Side SCR Configuration**

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3)			Title		Units	U	Inc	Val	ue	Calc	Min	Max	Defau	lt
ж1	1	Catalyst Rep	lacement Schen	ne				Each	-		Menu	Menu	Each	
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Hot–Side SCR – Config. input screen.

Inputs for configuring the **Hot–Side SCR**  $NO_x$  Control technology are entered on the **Config** input screen. Each parameter is described briefly below.

- **Catalyst Replacement Scheme:** Catalyst is installed in the SCR as a series of layers. These activity or effectiveness of these layers decreases with time due to fouling and poisoning. The layers are replaced with clean layers on a regular basis in one of two ways: all at once or one layer at time (staggered). The selection of the replacement scheme involves trade-offs between capital and annual costs via the initial catalyst requirement and the replacement interval. More specifically:
  - **Each** Individual Layers. Replacing individual layers sequentially, rather than simultaneously, increases the effective catalyst life for a given volume of catalyst, decreasing the replacement interval. This reduces the O&M cost relative to simultaneous replacement. The default setting is **Each**.
  - All All Layers: Simultaneous replacement may lead to a smaller initial catalyst volume to achieve the same design activity as a sequential replacement scheme. This reduces the capital cost but increases the O&M cost.

# **Hot-Side SCR Performance Inputs**

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		<u>C</u> onfigure Plant	Set <u>P</u> ara	met	ers			Get Res	ults	
O F	verall Plant	Fuel Base Plant Cons	tr <u>a</u> int Mercury	on Mercur <u>y N</u> Ox int Mercur <u>y</u> Control				1 C <u>O</u> 2 1 Captu	re By-Prod. <u>M</u> gmt	
		Title	Units	Unc	Value	Calc	Min	Max	Default	
	1	Actual NOx Removal Efficiency	%		50.00	M	50.00	95.00	calc	
	2	Maximum NOx Removal Efficiency	%		90.00		80.00	95.00	90.00	
	3	Particulate Removal Efficiency	%		0.0		0.0	100.0	0.0	
	4	Number of SCR Trains	number		2 🔻		Menu	Menu	2	
	5	Number of Spare SCR Trains	number		0 🔻		Menu	Menu	0	
	6									
	7	Number of Catalyst Layers								
	8	Dummy Layers	number		1 🔹		Menu	Menu	1	
	9	Initial Layers	number		3 🔻		Menu	Menu	3	
	10	Reserve Layers	number		0 🗸		Menu	Menu	0	
	11									
	12	Catalyst Replacement Interval	hours		1.000e+04		100.0	4.000e+04	calc	
	13	Catalyst Space Velocity	1/hr		5198		100.0	8000	calc	
	14	Ammonia Stoichiometry	mol N/mol NOx		0.5320	M	0.0	4.000	calc	
	15	Steam to Ammonia Ratio	mol H2O/mol NH3		19.00		0.0	50.00	19.00	
	16	Total Pressure Drop Across SCR	in H2O gauge		9.000		0.0	20.00	calc	
	17	Oxidation of SO2 to SO3	vo1 %		0.5636		0.0	100.0	calc	
	18	Hot-Side SCR Power Requirement	% MWg	?	0.5248		0.0	10.00	calc	
	Pror	ess Type: Hat Side SCD	-							

*Hot–Side SCR – Performance input screen.* 

Inputs for the performance of the Hot–Side SCR  $NO_x$  control technology are entered on the on the **Performance** input screen. Each parameter is described briefly below.

- Actual NOx Removal Efficiency: The actual removal efficiency is dependent on the minimum and maximum removal efficiencies of the SCR and the emission constraint for  $NO_x$ . The model assumes a minimum removal of 50%. The actual removal is set to match the constraint, if feasible. It is possible that the SCR may under or over comply with the emission constraint. This input is highlighted in blue.
- **Maximum NOx Removal Efficiency:** This parameter specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual NO_x removal efficiency for compliance.
- **Particulate Removal Efficiency:** The ash in the high dust gas entering the SCR collects on the catalyst layers and causes fouling. Ash removal is not a design goal; rather, it is a reality which is taken into consideration by this parameter.
- **Number of SCR Trains:** This is the total number of SCR equipment trains. It is used primarily to calculate the capital costs. The value must be an integer.
- **Number of Spare SCR Trains:** This is the total number of spare SCR equipment trains. It is used primarily to calculate capital costs. The value must be an integer.
- **Number of Catalyst Layers:** The total number of catalyst layers is a sum of the dummy, initial and spares used. All catalyst layer types are of equal dimensions, geometry, and catalyst formulation. You specify each value; the value must be an integer. The catalyst layer types and quantities are combined with pressure drop information to determine the auxiliary power requirements and the capital cost of the SCR technology. A layer may be interpreted as either a full layer (e.g.,

typically 1 meter deep), or a half layer (e.g., typically 0.5 meters deep) to represent alternative SCR catalyst replacement schemes. There is a limit of 8 total initial and reserve layers.

- **Dummy Layers:** This is the number of dummy catalyst layers. The value must be an integer. A dummy layer corrects the flow distribution. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.
- **Initial Layers:** This is the number of initial active catalyst layers. The value must be an integer. Three layers are installed initially. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.
- **Reserve Layers:** This is the number of reserve or extra catalyst layers. These are available for later catalyst additions. The value must be an integer. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.
- **Catalyst Replacement Interval:** This parameter calculates the operating hour interval between catalyst replacements. The interval is determined by the decision to replace all at once or each of them separately after each interval. Currently, the model is not set up to replace two half layers simultaneously.
- **Catalyst Space Velocity:** The calculated space velocity is determined by several factors, including many of the reference parameters in the next Section. The space velocity is used to determine the catalyst volume required.
- **Ammonia Stoichiometry:** This is the molar stoichiometry ratio of ammonia to  $NO_x$  entering the SCR device. The calculated quantity is based on an assumed  $NO_x$  removal reaction stoichiometry of 1:1 for both NO and  $NO_2$ , and a specified ammonia slip. It affects the amount of ammonia used and the amount of  $NO_x$  converted to moisture.
- **Steam to Ammonia Ratio:** The molar ratio of steam to ammonia is used to determine the amount of steam injected to vaporize the ammonia. The value assumes the steam is saturated at 450 degrees Fahrenheit and the ammonia is diluted to 5 volume percent of the injected gas.
- **Total Pressure Drop Across SCR:** The total is determined from the individual pressure drops due to air preheater deposits, the active catalyst layers, the dummy catalyst layers, the ammonia injection system and the duct work. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.
- **Oxidation of SO₂ to SO₃:** The oxidation rate is calculated for a high sulfur catalyst and affects the flue gas composition. It uses the space velocity and the inlet temperature. The SO₃ produced acts as an ash-conditioning agent if an ESP is used downstream.
- **Hot-Side SCR Power Requirement:** The default calculation of auxiliary power is based on the additional pressure drop, electricity to operate pumps and compressors, and equivalent energy for steam consumed. It is expressed as a percent of the gross plant capacity.

# Hot-Side SCR Performance (Continued)

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	Or P	verall 'lant	Fuel Ba	ise Plant Cc	mission mstr <u>a</u> int	on Mercury <u>N</u> Ox int Mercury Control Co			SP ntro1	<u>S</u> O2 Control	C <u>O</u> 2 Captu	re By-	Prod. gmt
3			Ti	tle		Units	Unc	Value	Calc	Min	Max	Default	
<u>x 1</u>		1	Reference l	Parameters									
		2	Space Velocity			1/hr		2500		100.0	8000	2500	
		3	Catalyst Replacen	ient Interval		hours		5694		0.0	1.000e+04	5694	
e		4	Ammonia Slip			ppmv	?	5.000		0.0	None	5.000	
91		5	Temperature		deg. R		1160		900.0	1300	1160		
		6	NOx Removal Effi	ciency		%		80.00		50.00	95.00	80.00	
<u> </u>		7	NOx Concentration			ppmw		500.0		50.00	5000	500.0	
2		8											
		9	Reference Cat	<u>alyst Activity</u>									
		10	Minimum Activity					0.5000		0.0	1.000	0.5000	
		11	Reference Time			hours		1.000e+04		0.0	2.500e+04	1.000e+04	
		12	Activity at Referen	nce Time				0.8500		0.0	1.000	0.8500	
		13											
		14	Ammonia Deposit	ion on Prehea	ter	%		5.000		0.0	25.00	5.000	
		15	Ammonia Deposit	ion on Fly As	h	%		50.00		0.0	100.0	50.00	
		16	Ammonia in High	Conc. Wash V	V	mg/l		310.0		0.0	1000	310.0	
		17	Ammonia in Low (	Conc. Wash V	Va	mg/l		40.00		0.0	100.0	40.00	
		18	Ammonia Remove	d from Wash	W	%		67.00		0.0	100.0	67.00	
		Proc	ess Type: Hot-S	ide SCR		-							
	K	<u>1</u> . C	onfig <u>2</u> .P	erformance	3.1	Perf(cont.)	<u>4</u> . F	Retrofit Cost	1	. Capital C	ost 6	. O&M Co	st

Hot-Side SCR - Perf.(cont.) input screen

The Hot-Side SCR system has additional inputs for performance entered on the **Perf (Cont.)** input screen. Many of the calculated quantities on the **Performance** screen are determined by the reference parameters described below.

#### **Reference Parameters**

The first set of reference parameters is primarily used to determine the actual space velocity. The values are used with actual operating conditions through a series of correction factors in the IECM. If you set the actual space velocity displayed on the **Performance** screen, this set of input parameters is not used by the IECM and does not have to be set.

- **Space Velocity:** This is the reference space velocity for a high dust system. It is used to calculate the actual space velocity.
- **Catalyst Replacement Interval:** This is the reference operating life in hours associated with the reference space velocity for the high dust catalyst. It is used to calculate the actual space velocity.
- **Ammonia Slip:** Ammonia slip accounts for the ammonia passing through the reactor unchanged and further downstream. The value is based on an 80 percent or lower  $NO_x$  removal efficiency. It is used in calculating the ammonia stoichiometry and actual space velocity.
- **Temperature:** This is the operating temperature associated with the reference space velocity. It is used to determine the actual space velocity.
- **NO_x Removal Efficiency:** This is the NO_x removal efficiency associated with the reference design specifications for the SCR system. It is used to determine the actual space velocity.
- **NO_x Concentration:** This is the inlet NO_x concentration associated with the reference design specifications for the SCR system. It is used to determine the actual space velocity

#### **Reference Catalyst Activity**

Catalyst activity decreases with operating time due to plugging and catalyst poisoning. The loss is a complex function of the catalyst formulation and geometry, the operating conditions associated with the flue gas, including temperature and composition, and the loading and composition of the fly ash. This complex function is represented by an exponential decay formula in the IECM. The following parameters are used to determine the reference catalyst activity, assuming the initial activity has a value of unity:

- **Minimum Activity:** The minimum activity is a lower limit for catalyst activity decay. The actual activity approaches this value over a long period of time.
- **Reference Time:** This is the time that corresponds to a particular activity known for the catalyst. It is used to determine a decay rate constant.
- Activity at Reference Time: A second activity reference point is needed to determine the activity decay rate. The activity should correspond to the reference time specified. It is used to determine a decay rate constant.
- Ammonia Deposition on Preheater: This is the percent of the ammonia slip that is deposited as ammonium salts in the air preheater. It is treated like a partition coefficient.

#### **Ammonia Parameters**

- Ammonia Deposition on Fly Ash: This is the percent of the ammonia slip that is absorbed onto the fly ash. It is treated like a partition coefficient. This is important for high dust systems.
- Ammonia in High Conc. Wash Water: The ammonia that deposits in the air preheater is periodically removed by washing. It is initially highly concentrated and requires denitrification pretreatment prior to regular treatment. This is the average concentration in that stream.
- **Ammonia in Low Conc. Wash Water:** The ammonia that deposits in the air preheater is periodically removed by washing. The concentration is initially high, but gradually decreases. This is the average concentration of the low concentration stream.
- **Ammonia Removed from Wash Water:** The ammonia that deposits in the air preheater is periodically removed by washing. This is the average amount of ammonia removed from the high and low concentrated streams.

# Hot-Side SCR Retrofit Cost

E	dit <u>V</u> iew 6	io <u>W</u> indow <u>H</u>	<u>H</u> elp									
		<u>C</u> onfigure I	Plant	Ì	Set <u>P</u> ar	amete	ers	Ĩ	<u>(</u>	<u>G</u> et Res	sults	
	Ove <u>r</u> all Plant	Fuel	Base Plant	<u>M</u> ercury	<u>N</u> Ox Control	Con	SP itro1 Co	CQ2 Capture Mgmt Stack				
l			Title		Units	Unc	Value	Calc	Min	Max	Default	
I	1	Capital C	ost Process Are	a								
I	2	Reactor Hous	aing		retro \$/new \$		1.000		0.0	10.00	1.000	
I	3	Ammonia Inje	ection		retro \$/new \$		1.000		0.0	10.00	1.000	
II	4	Ducts			retro \$/new \$		1.000		0.0	10.00	1.000	
I	5	Air Preheater	Modifications		retro \$/new \$		1.000		0.0	10.00	1.000	
II	6	ID Fan Differ	ential		retro \$/new \$		1.000		0.0	10.00	1.000	
II	7	Structural Suj	pport		retro \$/new \$		1.000		0.0	10.00	1.000	
II	8	Misc. Equipm	ient		retro \$/new \$		1.000		0.0	10.00	1.000	
II	9											
II	10											
II	11											
II	12											
I	13											
II	14											
II	15											
II	16											
I	17											
1	18											
	Proc	ess Type:	lot-Side SCR		~							
I	1.0	opfia /	2 Performance	/ 2	Perf(cont)	1 1	etrofit Cost	5	Conital Co.	et /	6 O&MCo	et /

Hot–Side SCR – Retrofit Cost input screen.

The **Hot-Side SCR** system has inputs for the capital costs of modifications to process areas necessary to implement the technology entered on the **Retrofit Cost** input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens. Each parameter is described briefly below.

## **Capital Cost Process Area**

- **Reactor Housing:** The reactor housing costs include carbon steel reactor vessel with six inches of mineral wool insulation, vessel internals and supports, steam sootblowers, reactor crane and hoist, installation, labor, foundations, structures, piping, and electrical equipment.
- **Ammonia Injection:** The ammonia unloading, storage, and supply system includes a storage vessel with a seven day capacity, an ammonia vaporizer, mixer, injection grid, ductwork, dampers, and a truck unloading station.

- **Ducts:** The ductwork includes economizer bypass and outlet ducts, SCR inlet and outlet ducts, SCR and economizer control dampers, air preheater inlet plenum, various expansion joints in the ductwork, and air preheater cross-over ducting.
- Air Preheater Modifications: Thicker and smoother material is used for the heat transfer surfaces in the preheater. A larger motor is provided for the heat exchanger. High pressure steam soot blowers and water wash spray nozzles are also added.
- **ID Fan Differential:** The ID fans must be sized to deal with the increased flue gas pressure drop resulting from the additional ductwork and the SCR reactor.
- **Structural Support:** The costs of this area are related primarily to the structural support required for the SCR reactor housing, ductwork, and air preheater.
- **Misc. Equipment:** This area includes the capital costs incurred for ash handling addition, water treatment addition, and flow modeling for a hot-side SCR system.

## **Hot-Side SCR Capital Cost Inputs**

This screen is only available for the Combustion (Boiler) plant type.

onnico	Configure Plant	Set Par	amete	****	Ĩ	Get Deculta			
Ove <u>r</u> all Plant	Fuel Base Plant Mer	cury <u>N</u> Ox Control	<u>T</u> S Con	SP Softrol Con	O2 ntro1	CO2 Capture Mgmt Stack			
	Title	Units	Unc	Value	Calc	Min	Max	Default	
1	Construction Time	years		2.000		0.2500	10.00	2.000	
2	General Facilities Capital	%PFC		10.00		0.0	50.00	10.00	
3	Engineering & Home Office Fees	%PFC		10.00		0.0	50.00	10.00	
4	Project Contingency Cost	%PFC		10.00		0.0	100.0	10.00	
5	Process Contingency Cost	%PFC		4.932	V	0.0	100.0	calc	
6	Royalty Fees	%PFC		0.0		0.0	10.00	0.0	
7									
8	Pre-Production Costs								
9	Months of Fixed O&M	months		1.000		0.0	12.00	1.000	
10	Months of Variable O&M	months		1.000		0.0	12.00	1.000	
11	Misc. Capital Cost	%TPI		2.000		0.0	10.00	2.000	
12									
13	Inventory Capital	%TPC		0.5000		0.0	10.00	0.5000	
14									
15									
16									
17									
18	TCR Recovery Factor	%		100.0		0.0	100.0	100.0	
Proc	ess Type: Hot Side SCR								

Hot-Side SCR - Capital Cost input screen.

Inputs for the capital costs of the Hot–Side SCR  $NO_x$  control technology are entered on the **Capital Cost** screen for the Hot-Side SCR, and the **Capital Cost** input screen for In-Furnace Controls. Each parameter is described briefly below.

**Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

- **General Facilities Capital (GFC):** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.
  - **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
  - **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
  - **Misc. Capital Costs:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a hot-side SCR that has been paid off.

# Hot-Side SCR O&M Cost Inputs

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		<u>(</u>	<u>C</u> onfigure I	Plant	Ĭ	Set <u>P</u> ara	amet	ers	<u>G</u> et Results				
	Ove Pla	erall ant	Fuel	Base Plant	Emissio: Constr <u>a</u> i	n nt <u>M</u> ercury	<u>N</u> Con	Dx I atrol Co	SP ntrol	<u>S</u> O2 Control	. C <u>O</u> Capt	2 By-1 ure M;	Prod. gmt
9				Title		Units	Unc	Value	Calc	Min	Max	Default	
*		1	Catalyst Cost			\$/cu ft	?	324.2		250.0	750.0	calc	
Ba		2	Ammonia Cos	t		\$/ton		204.9		100.0	400.0	calc	
-		3	Electricity Pric	e (Base Plant)		\$/MWh		37.71		0.0	100.0	calc	
		4											
e l		5	Number of Op	erating Jobs		jobs/shift		0.4600		0.0	30.00	calc	
		6	Number of Op	erating Shifts		shifts/day		4.750		0.0	10.00	4.750	
		7	Operating Lab	or Rate		\$/hr		24.82		0.0	100.0	24.82	
<u>.</u>		8											
		9	Total Mainter	nance Cost		%TPC	?	2.000		0.0	10.00	2.000	
		10	Maint. Cost A	llocated to Labo	or	% total		40.00		0.0	100.0	40.00	
		11	Administrativ	e & Support Cos	st	% total labor		30.00		0.0	100.0	30.00	
		12											
		13											
		14											
		15											
		16											
		17											
		18											
		Proc	ess Type: H	ot Side SCR		-		Costs are	in Con	stant 2000	dollars.		
		<u>1</u> , C	onfig 🖌	2. Performance		.Perf(cont.)	<u>4</u> . F	letrofit Cost	1 2	. Capital Co	ost	<u>6</u> . O&M Cos	st

Hot-Side SCR - O&M Cost input screen.

Inputs for the operation and maintenance costs of the **Hot–Side SCR**  $NO_x$  control technology are entered on the **O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below.

- **Catalyst Cost:** This is the cost of the catalyst used for the SCR technology.
- Ammonia Cost: This is the cost of the ammonia used for the SCR technology.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work ( 3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks 6 weeks PTO) = 4.75 equiv. Shifts/day).
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

## Hot-Side SCR Diagram

This screen is only available for the Combustion (Boiler) plant type.



*Hot–Side SCR – Diagram result screen.* 

The **Diagram** result screen displays an icon for the **Hot–Side SCR**  $NO_x$  technology selected and values for major flows in and out of it.

#### Reagent

- **Ammonia Injection:** The total mass flow rate of ammonia injected into the SCR. This is a function of the  $NO_x$  concentration in the flue gas and the ammonia stoichiometric performance input value.
- **Steam for Injection:** The total mass flow rate of steam into the SCR. This is the amount of steam added to the SCR to vaporize and transport ammonia into the inlet gas stream. This is determined by the steam to ammonia ratio input value and the ammonia injection.

### Catalyst

- **Steam for Soot:** This is the amount of steam blown into the hot-side SCR to remove soot buildup on the catalyst layers. The soot blowing steam is assumed to be directly proportional to catalyst volume.
- **Initial Catalyst Layers:** This is the number of initial active catalyst layers. Three layers are installed initially. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. This is set by the input parameter.

- **Reserve Catalyst Layers:** This is the number of reserve or extra catalyst layers. These are available for later catalyst additions. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. This is set by the input parameter.
- **Dummy Catalyst Layers:** This is the number of dummy catalyst layers. A dummy layer corrects the flow distribution. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. This is set by the input parameter.
- Active Catalyst Layers: This is the number of initial active catalyst layers. Three layers are installed initially. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. It is equal to the number of initial and reserve catalyst layers.
- **Layers Replaced Yearly:** Average catalyst layer replacement rate per year. This assumes that all catalyst layers are of equal depth.

## Flue Gas Entering SCR

- **Temperature In:** Temperature of the flue gas entering the SCR. This is determined by the flue gas outlet temperature of the module upstream of the SCR (e.g., the boiler economizer)
- Flue Gas In: Volumetric flow rate of flue gas entering the SCR, based on the flue gas temperature entering the SCR and atmospheric pressure.
- **Fly Ash In:** Total solids mass flow rate in the flue gas entering the SCR. This is determined by the solids exiting from the module upstream of the SCR (e.g., the boiler economizer).
- **Mercury In:** Total mass of mercury entering the hot-side SCR in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

## Flue Gas Exiting SCR

- **Temperature Out:** Temperature of the flue gas exiting the SCR. The model currently does not alter this temperature through the SCR.
- Flue Gas Out: Volumetric flow rate of the flue gas exiting the SCR, based on the flue gas temperature exiting the SCR and atmospheric pressure.
- **Fly Ash Out:** Total solids mass flow rate in the flue gas exiting the SCR. This is a function of the ash removal parameter on the SCR performance input screen.
- **Ammonia Slip:** Total mass flow rate of ammonia that is unreacted and exits the SCR in the flue gas stream. This is a function if the ammonia injection flow rate,  $NO_x$  concentration in the flue gas, and  $NO_x$  removal efficiency.
- **Mercury Out:** Total mass of mercury exiting the hot-side SCR in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

### **SCR Performance**

**NOx Removal:** Actual removal efficiency of  $NO_x$  in the SCR. This is a function of the minimum (50%) and maximum removal efficiencies

(SCR performance input parameter) and the emission constraint for  $NO_x$  (emission constraints input parameter). It is possible that the SCR may over or under-comply with the emission constraint.

**TSP Removal:** Actual particulate removal efficiency in the SCR. This is set by the SCR input parameter.

### **Collected Solids**

**Dry Solids:** Total solids mass flow rate of solids removed from the SCR. This is a function of the solids content in the flue gas and the particulate removal efficiency of the SCR.

# **Hot-Side SCR Flue Gas Results**

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6	ľ	<u>(</u>	<u>C</u> on:	figure	e Plant	Ĩ	Se	t <u>P</u> aramet	er	s	Ĩ	<u>(</u>	<u>G</u> et Results		
	ľ	Overall Fuel Boiler Air NOx Plant Fuel Boiler Preheater Control I							с	<u>T</u> SP <u>S</u> C Control Con		02 C <u>O</u> 2 ntrol Captu		re By-Prod. <u>M</u> gmt	Stack
*					Major Flue	Gas Compo	onents	Flue Gas h (b-moles/h	n r)	Flue Gas (Ib-mole	s Out s/hr)	Flue (to	Gas In n/hr)	Flue Gas Out (ton/hr)	
	I		1	Nitrog	gen (N2)			1.093e+05	5	1.093e	+05	1	531	1531	
	I		2	Oxyge	en (O2)			4818		481	6	7	7.09	77.05	
	I		<ul><li>3 Water Vapor (H2O)</li><li>4 Carbon Dioxide (CO2)</li></ul>					1.298e+04	1	1.343e+04		117.0		121.0	
8	I							2.050e+04	1	2.050e	+04	451.0		451.0	
<b>N</b> ?	II		5	Carbo	n Monoxide	(CO)		0.0		0.0		0.0		0.0	
١	II		6	Hydro	chloric Acio	I (HCI)		5.643		5.64	3	0.1	1029	0.1029	
	II		7	Sulfur	Dioxide (SC	2)		214.2		213.	.0	6.	862	6.823	
	II		8	Sulfur	ic Acid (equ	ivalent SO3	)	1.728		2.93	5	6.91	6e-02	0.1175	
	II		9	Nitric	Oxide (NO)			21.98		10.9	9	0.3	3298	0.1649	
	II		10	Nitrog	gen Dioxide (	NO2)		1.157		0.571	83	2.68	61e-02	1.330e-02	
	II		11	Ammo	onia (NH3)			2.595		0.73	92	2.21	0e-02	6.294e-03	
	II		12	Argor	ı (Ar)			0.0		0.0		1	D.O	0.0	
	I		13	Total				1.478e+05	5	1.483e	+05	2	183	2187	
	I		14						_						
	I		15												
		Process	Туре	: Ho	ot-Side SC	R Gas /	•	ost / 4	0.8	2M Cost		5 T	otal Cost		
	L	<u>I</u> . Di	aStan		Z. Fiue		2. Capital C	USI <u>4</u> .	06	xior COSt		2.1	orarcosi		

This screen is only available for the Combustion (Boiler) plant type.

*Hot–Side SCR – Flue Gas result screen.* 

#### **Major Flue Gas Components**

The **Flue Gas** result screen for the **Hot-Side SCR** displays a table of quantities of flue gas components entering and exiting the SCR. For each component, quantities are given in both moles and mass per hour. Each result is described briefly below.

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCI): Total mass of hydrochloric acid.
Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **Hot-Side SCR Capital Cost Results**

This screen is only available for the Combustion (Boiler) plant type.

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	Γ		<u>C</u> onfigure Plant	Set <u>P</u> ar	ame	ters <u>G</u> et Re	sults
		Ove; Plai	rall F <u>u</u> el <u>B</u> oiler <u>A</u> ir nt F <u>u</u> el <u>B</u> oiler Preheater	<u>N</u> Ox Control Mer	cury	TSP <u>S</u> O2 C <u>O</u> 2 By Control Control Capture M	r-Prod. Mgmt Stac <u>k</u>
*			SCR Process Area Costs	Capital Cost (M\$)		SCR Plant Costs	Capital Cost (M\$)
E.		1	Reactor Housing	4.365	1	Process Facilities Capital	20.45
1 1 1	Ш	2	Ammonia Injection	0.3946	2	General Facilities Capital	2.045
	Ш	3	Ducts	4.438	3	Eng. & Home Office Fees	2.045
	Ш	4	Air Preheater Modifications	1.063	4	Project Contingency Cost	2.045
$\rightarrow$	Ш	5	ID Fan Differential	0.1672	5	Process Contingency Cost	1.009
21	Ш	6	Structural Support	1.845	6	Interest Charges (AFUDC)	1.421
2	Ш	7	Misc. Equipment	0.5019	7	Royalty Fees	0.0
<u>~</u>	Ш	8	Initial Catalyst	7.680	8	Preproduction (Startup) Cost	0.9104
	Ш	9	Process Facilities Capital	20.45	9	Inventory (Working) Capital	0.1380
	Ш	10			10	Total Capital Requirement (TCR)	30.07
	Ш	11			11		
	Ш	12			12		
	Ш	13			13		
	Ш	14			14		
		15			15	Effective TCR	30.07
		Pro	acess Type: Hot-Side SCR	Y		Costs are in Constant 2005 dollars.	
			1. Diagram 🔏 2. Flue Gas <u>3</u> .	Capital Cost	4	.O&MCost / <u>5</u> .TotalCost /	

Hot-Side SCR - Capital Cost result screen.

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the **Hot–Side SCR**  $NO_x$  control technology. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

#### **Direct Capital Costs**

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of hot-side SCR units. They are described in general with specific model parameters that effect them described in particular.

**Reactor Housing:** The reactor housing costs include carbon steel reactor vessel with six inches of mineral wool insulation, vessel internals and supports, steam soot blowers, reactor crane and hoist, installation labor, foundations, structures, piping, and electrical equipment. The costs are

a function of the number of vessels, including spares, and the volume of catalyst required. Catalyst costs are excluded.

- **Ammonia Injection:** The ammonia unloading, storage, and supply system includes a storage vessel with a seven day capacity, an ammonia vaporizer, mixer, injection grid, ductwork, dampers, and a truck unloading station. The costs are a function of the ammonia injected.
- **Ducts:** The ductwork includes economizer bypass and outlet ducts, SCR inlet and outlet ducts, SCR and economizer control dampers, air preheater inlet plenum, various expansion joints in the ductwork, and air preheater cross-over ducting. The costs are a function of the flue gas flow rate through the SCR.
- Air Preheater Modifications: Thicker and smoother material is used for the heat transfer surfaces in the preheater. A larger motor is provided for the heat exchanger. High pressure steam soot blowers and water wash spray nozzles are also added. The costs are a function of the number of operating vessels, and the heat transfer efficiency of the air preheater (UA product).
- **ID Fan Differential:** The ID fans must be sized to deal with the increased flue gas pressure drop resulting from the additional ductwork and the SCR reactor. The costs are a function of the flue gas flow rate and pressure drop across the SCR.
- **Structural Support:** The costs of this area are related primarily to the structural support required for the SCR reactor housing, ductwork, and air preheater. The costs are a function of the reactor housing costs, duct costs and air preheater modification costs above.
- **Misc. Equipment:** This area includes the capital costs incurred for ash handling addition, water treatment addition, and flow modeling for a hot-side SCR system. The costs are a function of the gross plant capacity.
- **Initial Catalyst:** The cost of the initial catalyst charge is included in the total direct cost, because it is such a large and integral part of the SCR system. The costs are a function of the initial catalyst charge.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

#### **Total Capital Costs**

Process Facilities Capital: (see definition above)

- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the hot-side SCR that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the hot-side SCR.

# Hot-Side SCR O&M Cost Results

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2			Configure Plant	Set <u>P</u> ara	amet	ers <u>G</u> et Re	sults
	ſ	Ovej Plaz	all Fuel <u>B</u> oiler <u>A</u> ir t Preheater (	<u>N</u> Ox Control <u>M</u> ero	ury	TSP <u>S</u> O2 C <u>O</u> 2 By Control Control Capture I	r-Prod. Mgmt Stac <u>k</u>
			Variable Cost Component	O&M Cost (M\$/yr)		Fixed Cost Component	O&M Cost (M\$/yr)
3		1	Catalyst	1.683	1	Operating Labor	0.1386
all		2	Ammonia	0.5587	2	Maintenance Labor	0.1593
-11		3	Steam	0.3551	3	Maintenance Material	0.2390
-		4	Water	1.720e-03	4	Admin. & Support Labor	8.938e-02
		5	Electricity	0.7356	5	Total Fixed Costs	0.6263
		6	Total Variable Costs	3.334	6		
		7			7		
ᅦ		8			8		
		9			9		
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	I	11			11		
	I	12			12		
		13			13		
		14			14	Total O&M Costs	3 961
		Pro	cess Type: Hot-Side SCR	7		Costs are in Constant 2005 dollars.	
	Ĺ		1. Diagram / 2. Flue Gas / 3.	Capital Cost 🧳	4	O&M Cost 5. Total Cost	

This screen is only available for the Combustion (Boiler) plant type.

Hot-Side SCR – O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **Hot Side SCR**  $NO_x$  control technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

### **Variable Cost Components**

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

- **Catalyst:** Replacement catalyst cost per year for the hot-side SCR. This is a function of the number of catalyst layers, the number of layers replaced each year, and the catalyst space velocity (all three are performance input parameters).
- **Ammonia:** Ammonia reagent cost per year for the hot-side SCR. This is a function of the concentration of  $NO_x$  in the flue gas and the ammonia mass flow rate.
- **Steam:** Annual cost of steam used for ammonia vaporization and ammonia injection. This is a function of the steam to ammonia ratio (performance input parameter) and the ammonia mass flow rate.
- **Water:** Cost of water used to wash ammonia that deposits in the air preheater. This is a function of the efficiency and concentration of ammonia removed by wash water performance input parameters and the amount of ammonia salts deposited on the air preheater.
- **Electricity:** Cost of electricity consumption of the hot-side SCR. This is a function of the gross plant capacity and the SCR energy penalty performance input parameter.
- **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

# **Hot-Side SCR Total Cost Results**

This screen is only available for the Combustion (Boiler) plant type.

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		Overail Plant	F	'uel <u>B</u> oiler <u>A</u> ir <u>N</u> Ox Preheater Control	Mercury	TSP SO Control Cor	02 CO2 itrol Captu	re By-Prod. Mgmt	Stac <u>k</u>
*				Cost Component	M\$/yr	\$/MWh	\$/ton NO2 removed	Percent Total	
Ē.			1	Annual Fixed Cost	0.6263	0.2871	103.7	7.447	
r an			2	Annual Variable Cost	3.334	1.528	552.3	39.64	
			3	Total Annual O&M Cost	3.961	1.816	656.0	47.09 53.01	
			4	Total Levelized Annual Cost	4.400 8.411	3.856	1393	100.0	
			6		0.411	0.000	1000	100.0	
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		Process	Гуре	Hot-Side SCR		Costs are in Co	onstant 2005 d	ollars.	
		<u>1</u> . Dia	grar	n 🔏 2. Flue Gas 🔏 3. Capital C	ost 🖌 <u>4</u> .0	&M Cost	<u>5</u> . Total Cost		

Hot-Side SCR – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Hot–Side SCR**  $NO_x$  Control technology. Note that all costs expressed in \$/ton of  $NO_2$  removed assume tons of equivalent  $NO_2$ . Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

### **Cost Component**

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# Mercury

**Mercury Control** is a Technology Navigation Tab in the **Set Parameters** and in the **Get Results** program area. These screens define and display results for the performance and costs directly associated with the removal of mercury from each technology in the power plant Pre-combustion and post-combustion control technologies are all considered. Special consideration is given to flue gas conditioning used to enhance mercury removal. Water and activated carbon injection are currently considered as conditioning agents.

# **Mercury Removal Efficiency Inputs**

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for the removal of the speciated mercury from the flue gas stream are entered on the **Removal Eff.** input screen.

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6			Title	Units	Unc	Value	Calc	Min	Max	Default	
X		1	Removal Efficiency of Mercury								
Ba		2	Furnace Removal (total)	%	?	7.000		0.0	100.0	calc	
		3	Spray Dryer (oxidized)	%		0.0	V	0.0	100.0	calc	
- 64		4	Spray Dryer (elemental)	%		0.0	M	0.0	100.0	calc	
P		5	Spray Dryer (particulate)	%		0.0	V	0.0	100.0	calc	
<u>_</u>		6	Cold-Side ESP (total w/o control)	%		31.00	Ľ	0.0	100.0	calc	
		7	Cold-Side ESP (oxidized)	%		90.00	M	0.0	100.0	calc	
<u> </u>		8	Cold-Side ESP (elemental)	%		90.00	M	0.0	100.0	calc	
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		Proc	ess Type: Activated Carbon Inj								
		<u>1</u> . Rem	oval Eff. <u>2</u> . Carbon Inj.	3. Retrofit Cost	4.C	apital Cost		<u>5</u> .0&M			

Mercury – Removal Efficiency input screen.

Each parameter is described briefly below.

### **Removal Efficiency of Mercury**

The removal of mercury for each control technology configured is given as a percent of the total entering the control technology. The user is given the opportunity to specify the removal separately for each speciation type. Control technologies not currently configured are hidden.

**Furnace Removal (total):** Mercury present in ash is removed from the furnace through the removal of bottom ash. The speciation is not known, so the removal is specified as a total removal. The mercury removed in bottom ash is not credited toward the required removal to meet the mercury emission constraint.

## **Fabric Filter**

- **Fabric Filter (total w/o control):** Mercury present in ash is removed from the fabric filter through the removal of captured fly ash. The speciation is not known, so the removal is specified as a total removal. The value shown is determined without regard to particular mercury control methods. It has a substantial effect on the amount of activated carbon needed to meet the required removal of mercury.
- Fabric Filter (oxidized): The fabric filter typically removes some mercury without adding a specific mercury control technology. This mercury is present in the ash and is removed with the collected ash. When a mercury control technology is added, the removal is enhanced. The default value is set to meet the overall removal efficiency constraint, with consideration given to the mercury removed by flue gas desulfurization and elemental mercury oxidized in a NO_x control technology. The lower limit is set by the removal efficiency of ash alone as specified by "Fabric Filter (total w/o control)" specified above.
- **Fabric Filter (elemental):** Elemental mercury is assumed to be removed with the same efficiency as the removal of oxidized mercury specified above.

# Cold – Side ESP

- **Cold-Side ESP (total w/o control):** Mercury present in ash is removed from the cold-side ESP through the removal of captured fly ash. The speciation is not known, so the removal is specified as a total removal. The value shown is determined without regard to particular mercury control methods. It has a substantial effect on the amount of activated carbon needed to meet the required removal of mercury.
- **Cold-Side ESP (oxidized):** The cold-side ESP typically removes some mercury without adding a specific mercury control technology. This mercury is present in the ash and is removed with the collected ash. When a mercury control technology is added, the removal is enhanced. The default value is set to meet the overall removal efficiency constraint, with consideration given to the mercury removed by flue gas desulfurization and elemental mercury oxidized in a NO_x control technology. The lower limit is set by the removal efficiency of ash alone as specified by "Cold-Side ESP (total w/o control)" specified above.

**Cold-Side ESP (elemental):** Elemental mercury is assumed to be removed with the same efficiency as the removal of oxidized mercury specified above.

### Wet FGD

- Wet FGD (oxidized): The wet lime/limestone FGD typically removes all the oxidized mercury due to its' high solubility in water.
- Wet FGD (elemental): Elemental mercury is assumed to pass through the wet lime/limestone FGD. It is assumed that elemental mercury is present in the flue gas and is unreactive.

### **Spray Dryer**

- **Spray Dryer (oxidized):** Oxidized mercury is assumed to pass through the lime spray dryer. Although soluble in water, moisture injected into the spray dryer evaporates, resulting in the mercury remaining in the flue gas. The default value is zero.
- **Spray Dryer (elemental):** Elemental mercury is assumed to pass through the lime spray dryer. It is assumed that elemental mercury is present in the flue gas and is unreactive.

### **Percent Increase in Speciation**

Although  $NO_x$  control technologies do not remove mercury from the flue gas, they can change the mercury from one form to another. This is particularly true when catalysts are present. In this case, elemental mercury is converted to oxidized mercury. The parameters in this section define the percent increase in oxidized mercury across the control technology.

- **In-furnace NOx (oxidized):** Low NO_x burners with or without overfire air and gas reburn can effect the amount of oxidized mercury. At present, there is insufficient information available to specify a default value. The default is set to zero.
- **SNCR (oxidized):** An SNCR does not affect the relative amounts of oxidized and elemental mercury. The default is set to zero.
- **Hot-Side SCR (oxidized):** Hot-side SCR as a control technology chances elemental mercury to oxidized mercury. It is believed that the catalyst is responsible for this shift in speciation. The default value is a function of the coal rank.

# **Mercury Carbon (and Water) Injection Inputs**

This screen is only available for the Combustion (Boiler) plant type. Inputs for activated carbon and water injected into the flue gas are entered on the **Carbon Inj.** input screen. Water can be optionally added to reduce the flue gas temperature and enhance the effect of the carbon on removing mercury. Note that the actual removal of the carbon and mercury are accomplished in particulate and flue gas desulfurization control technologies downstream

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\$			Title	Units	Unc	Value	Calc	Min	Max	Default	
11	1	Activate	d Carbon Injection	]							
	2	Approach to	Acid Saturation Temp.	deg. F		18.00		0.0	50.00	18.00	
	3	Sorbent Injec	tion Rate	1b C/Macfm		58.25	M	0.0	40.00	calc	
	4										
111	5	Carbon Inject	tion Power Requirem	% MWg		0.1858	V	0.0	10.00	calc	
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Mercury – Removal Efficiency input screen.

Each parameter is described briefly below.

### **Activated Carbon Injection**

Injection of water to reduce the flue gas temperature and activated carbon to enhance mercury removal are the only control technologies presently incorporated into the IECM.

- **Approach to Acid Saturation Temperature:** When water is selected to be injected with the activated carbon this parameter appears on the **Removal Efficiency** input screen. It is important to keep the flue gas temperature above the sulfuric acid dew point temperature. This avoids condensation of acid on equipment. This parameter determines the amount of water injected into the flue gas. If the approach is above the actual temperature, the temperature is dropped to be the approach above the dew point. The dew point is a function of the SO₃ and H₂O content in the flue gas and the pressure of the flue gas.
- **Sorbent Injection Rate:** The flue gas temperature, the mercury removal efficiency in the particulate device, the coal rank, and the mercury removal efficiency without control, determines the injection rate of activated carbon into the flue gas. Mercury removal due to the ash removed in a cold-side ESP or fabric filter in the absence of enhanced mercury control methods is specified in the input screen. The default value is most sensitive to the flue gas temperature and the mercury removal efficiency without control.
- **Carbon Injection Power Requirement:** The power required for the water and carbon injection system is a function of carbon injection rate, the water injection rate, and the flue gas flow rate. This assumes the addition of a fan in the flue gas to balance the pressure drop. The default value is calculated as the ratio of the actual energy consumption by the gross electrical output of the power plant.

# **Mercury Retrofit Cost Inputs**

This screen is only available for the Combustion (Boiler) plant type. Inputs for the capital costs of modifications to process areas of the activated carbon and water injection system are entered on the **Retrofit Cost** input screen.

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茶	Ш	1	Capital C	Cost Process Area	1								
	Ш	2	Spray Coolin	g Water		retro \$/new \$		1.150		0.0	10.00	1.150	
2	Ш	3	Sorbent Injec	tion		retro \$/new \$		1.150		0.0	10.00	1.150	
	Ш	4	Sorbent Recy	7cle		retro \$/new \$		1.150		0.0	10.00	1.150	
	Ш	5	Additional D	uctwork		retro \$/new \$		1.150		0.0	10.00	1.150	
нI	Ш	6	Sorbent Disp	osal		retro \$/new \$		1.150		0.0	10.00	1.150	
	Ш	7	CEMS Upgra	ıde		retro \$/new \$		1.150		0.0	10.00	1.150	
-	Ш	8	Pulse-Jet Fab	oric Filter		retro \$/new \$		1.150		0.0	10.00	1.150	
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Mercury – Retrofit Cost input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Each parameter is described briefly below. Although the user cannot set the capital cost directly, the descriptions below include the key parameters used to determine the capital cost itself. The input parameters on this screen adjust this capital cost as calculated in the IECM.

## **Capital Cost Process Area**

**Spray Cooling Water:** This capital cost area represents the materials and equipment necessary to inject water into the flue gas duct for the

purpose of cooling the flue gas to a prerequisite temperature. Equipment includes water storage tanks, pumps, transport piping, injection grid with nozzles, and a control system. The direct capital cost is a function of the water flow rate.

- **Sorbent Injection:** This capital cost area represents the materials and equipment necessary to deliver the activated carbon into the flue gas. Equipment includes silo pneumatic loading system, storage silos, hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the sorbent flow rate.
- **Sorbent Recycle:** This capital cost area represents the materials and equipment necessary to recycle ash and activated carbon from the particulate collector back into the duct injection point. The purpose is to create a equilibrium state where the carbon is reintroduced to improve performance. Equipment includes hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the recycle rate of ash and spent sorbent.

NOTE: Sorbent recycling is a feature to be added in a future version of the IECM.

Additional Ductwork: This capital cost area represents materials and equipment for ductwork necessary beyond the other process areas. Extra ductwork may be required for difficult retrofit installations.

NOTE: Future versions of the IECM will include parameters to determine a capital cost for this area. The current version assumes no additional ductwork.

- **Sorbent Disposal:** This capital cost area represents materials and equipment required to house and dispose the collected sorbent. Equipment includes hoppers, blowers, transport piping, and a control system. This is in excess of existing hoppers, tanks, and piping used for existing particulate collectors. The direct capital cost is determined by the incremental increase in collected solids in the particulate collector.
- **CEMS Upgrade:** This capital cost area represents materials and equipment required to install a continuous emissions monitoring system (CEMS) upgrade. The direct capital cost is determined by the net electrical output of the power plant.
- **Pulse-Jet Fabric Filter:** This capital costs area represents an upgrade to an existing cold-side ESP, where one section at the back end of the unit is replaced with a pulse-jet fabric filter. This can be considered a pseudo-COHPAC. Equipment includes pulse-jet FF, filter bags, ductwork, dampers, and MCCs, instrumentation and PLC controls for baghouse operation. Equipment excludes ash removal system, power distribution and power supply, and distributed control system. The direct capital cost is a function of the flue gas flow rate and the air to cloth ratio of the fabric filter.

NOTE: The IECM currently does not support multiple particulate devices in the same configuration nor a modified cold-side ESP.

# **Mercury Capital Cost Inputs**

This screen is only available for the Combustion (Boiler) plant type. Inputs for the capital costs of the activated carbon and water injection system are entered on the **Capital Cost** input screen.

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X		1	Construction '	Time		years		1.000		0.2500	10.00	1.000	
		2											
		3	General Facilit	ies Capital		%PFC		5.000		0.0	20.00	5.000	
		4	Engineering &	: Home Office F	ees	%PFC		10.00		0.0	20.00	10.00	
ET.		5	Project Contin	igency Cost		%PFC		15.00		0.0	100.0	15.00	
←		6	Process Conti	ngency Cost		%PFC		5.000		0.0	100.0	5.000	
		7	Royalty Fees			%PFC		0.0		0.0	2.000	0.0	
		8											
		9	Pre-Pro	duction Costs				4 000	_		40.00	4 000	
<u>.</u>		10	Fixed Operatin	ig Cost		months		1.000	_	0.0	12.00	1.000	
		11	Variable Opera	ating Cost		months		1.000		0.0	12.00	1.000	
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		18	TCR Recovers	7 Factor		%		100.0		0.0	100.0	100.0	
		Proc	ess Type: 🛛	ctivated Carl	on Inj.			10010					
		<u>1</u> . Rem	oval Eff. 🖌	<u>2</u> . Carbon Inj.		3. Retrofit Cost	4.0	apital Cost		<u>5</u> . O&M Cos	st /		

Mercury – Capital Cost input screen.

The necessary capital cost input parameters associated with the base plant are on this input screen. The capital cost parameters and terminology used in the IECM are based on the methodologies developed by the Electric Power Research Institute (EPRI). They have prepared a Technical Assessment Guide (TAG) in order to provide a consistent basis for reporting cost and revenues associated with the electric power industry. This system of reporting is used by a wide audience, including energy engineers, researchers, planners, and managers. The IECM has been developed around this TAG system so that costs associated with various technologies can be compared directly on a consistent basis and communicated in the language used by the audience listed above.

Total Plant Cost (TPC) is the sum of the process facilities capital, general facilities capital, engineering and home office fees, and the contingencies (project and process). This is considered the cost on an instantaneous basis (overnight), and expressed in December dollars of a reference year.

Direct Capital Costs: Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). This is the basis for all other capital cost parameters.

The process facilities capital for the technology is the total constructed cost of all onsite processing and generating units, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. These direct capital costs are generally calculated by the IECM and not presented directly on input screens. However, when important input variables are required for these calculations, they are listed at the top of the input screen. Indirect Capital Costs: Costs that are indirectly applied to the technology are based on the process facilities cost. Each of the cost factors below is expressed as a percentage of the process facilities cost, and is entered on this screen. Each parameter is described briefly below.

- **Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).
- **General Facilities Capital (GFC):** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to O&M costs over a specified period of time (months).
  - **Fixed Operating Cost:** Time period of fixed operating costs (operating and maintenance labor, administrative and support labor, and maintenance materials) used for plant startup.
  - Variable Operating Cost: Time period of variable operating costs at full capacity (chemicals, water, and other consumables, and waste disposal changes) used for plant startup. Full capacity estimates of the variable operating costs will assume operations at 100% load.
  - **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for an activated carbon and water injection system that has been paid off.

# **Mercury O&M Cost Inputs**

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	Overall Plant Fuel Base Plant Mero		ury <u>N</u> Ox Control	T: Cor	SP <u>S</u> O2 ntrol Control		C <u>O</u> 2 Capture	By-Pr Mg	rod. Stac <u>k</u> mt	6	
			Title	Units	Unc	Value	Calc	Min	Max	Default	
	1	Activated Carb	oon Cost (w. shippi	\$/ton		1322		500.0	5000	calc	
Ш	2	Disposal Cost		\$/ton		13.86		0.0	30.00	calc	
	3	Electricity Price	e (Base Plant)	\$/MWh		41.12		0.0	200.0	calc	
	4										
	5	Number of Ope	erating Jobs	jobs/shift		0.1750		0.0	30.00	0.1750	
Ш	6	Number of Ope	erating Shifts	shifts/day		4.750		0.0	10.00	4.750	
	7	Operating Lab	or Rate	\$/hr		24.82		0.0	100.0	24.82	
	8										
	9	Total Maintena	ance Cost	%TPC		1.500e-02		0.0	10.00	calc	
Ш	10	Maint. Cost Al	llocated to Labor	% total		40.00		0.0	100.0	40.00	
Ш	11	Administrative	& Support Cost	% total labor		25.00		0.0	100.0	25.00	
	12										
	13										
	14										
	15										
	16										
Ш	17										
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	Pro	cess Type: Ac	tivated Carbon In	j. 🔽		Costs are	in Con	stant 2005	dollars.		
	<u>1</u> . Ren	noval Eff. 🖌	2. Carbon Inj.	3. Retrofit Cost	4.0	Capital Cost	$\overline{\lambda}$	5. O&M Cos	st /		_

This screen is only available for the Combustion (Boiler) plant type.

Mercury – O&M input screen.

Inputs for the operation and maintenance costs of the mercury control technology are entered on the **O&M** cost input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

- Activated Carbon Cost (w. shipping): This is the cost for the activated carbon, including the cost of shipping.
- **Disposal Cost:** This is the disposal cost for the particulate control system. It is assumed that the ash is not hazardous, therefore can be disposed with the collected fly ash.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work ( 3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks 6 weeks PTO) = 4.75 equiv. Shifts/day).
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

- **Maint. Cost Allocated to Labor:** Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

# **Mercury Diagram**

This screen is only available for the Combustion (Boiler) plant type. The **Diagram** result screen displays an icon for the water and carbon injection systems, both part of the overall mercury control option and values for major flows in and out of it

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See 5 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1		Water Injected (ton/hr) 11.25 Temperature In (deg. F) 300.0 Flue Gas In (acfm) 1.575e+06 Fly Ash In (ton/hr) 9.726			- Carbon Injected (ton/ Temperature Out (deg Flue Gas Out (acfm) Fly Ash Out (ton/hr)	hr) 2. 3. F) 26 1.54 12	762 31.0 7e+06 2.48
			Acid Dew Point Temp.	263.0	Carbon is C	Collected in	
					Particulat	te Control	
		Process Type: Activated Carbon In	j.				
		<u>1</u> . Diagram <u>2</u> . Flue Gas	🖌 <u>3</u> . Capital Cost 🖌 <u>4</u> .	O&M Cost	5. Total Cost	/	

Mercury— Diagram result screen

Each result is described briefly below in flow order (not from top to bottom and left to right as they display on the screen).

## Flue Gas Prior to Injection

- **Temperature In:** Temperature of the flue gas prior to flue gas conditioning.
- **Flue Gas In:** Volumetric flow rate of the flue gas prior to flue gas conditioning, based on the temperature prior to flue gas conditioning and atmospheric pressure.
- **Fly Ash In:** Total solids mass flow rate in the flue gas prior to flue gas conditioning. This includes ash, unburned carbon and unburned sulfur.

### **Flue Gas After Injection**

**Temperature Out:** Temperature of the flue gas after flue gas conditioning. This should be above the acid dew point temperature at the bottom of the screen.

- **Flue Gas Out:** Volumetric flow rate of the flue gas after flue gas conditioning, based on the temperature after flue gas conditioning and atmospheric pressure.
- **Fly Ash Out:** Total solids mass flow rate in the flue gas after flue gas conditioning. This includes ash, unburned carbon, activated carbon, and unburned sulfur.
- Acid Dew Point: This is the temperature that  $H_2SO_4$  vapor condenses into the liquid phase.

### **Flue Gas Conditioning**

- **Water Injected:** Water added to the flue gas to reduce the temperature No water is injected if water injection is not specified in the configuration or the inlet temperature is within the approach to saturation relative to the acid dew point.
- **Carbon Injected:** Total activated carbon mass flow rate injected into the flue gas.

NOTE: Carbon injected into the flue gas is collected downstream in the particulate control device (e.g., the cold-side ESP).

# **Mercury Flue Gas Results**

This screen is only available for the Combustion (Boiler) plant type. The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the flue gas conditioning area. For each component, quantities are given in both moles and mass per hour.

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	Overall Fuel <u>B</u> oiler <u>Air</u> <u>N</u> Ox Plant Fuel <u>B</u> oiler Preheater Control						Mercury	<u>T</u> SP <u>S</u> Control Co:	O2 C <u>O</u> 2 ntrol Captu	re By-Prod. <u>M</u> gmt	Stac <u>k</u>	
5				Major Flue	Gas Co	monents	Flue Gas In (B-moles/hr)	Flue Gas Out (b-moles/hr)	Flue Gas In (ton/hr)	Flue Gas Out (ton/hr)		
5			1	Nitrogen (N2)			1.266e+05	1.266e+05	1773	1773		
all			2	Oxygen (O2)			9402	9402	150.4	150.4		
-11			3	Water Vapor (H2C	))		1.361e+04	1.361e+04	122.7	122.7		
20			4	Carbon Dioxide (C	:02)		2.050e+04	2.050e+04	451.1	451.1		
?			5	Carbon Monoxide	(CO)		0.0	0.0	0.0	0.0		
-11			6	Hydrochloric Aci	4 (HCI)		5.643	5.643	0.1029	0.1029		
			7	Sulfur Dioxide (SC	)2)	~~	214.2	214.2	6.862	6.862		
			8	Sulfuric Acid (equ	uvalent 5	03)	0.8639	0.8639	3.4586-02	3.4586-02		
			9	Nitrogen Diovide	102		1 040	1 040	0.5266	4 251 0.02		
			10	Ammonia (NH2)	(102)		7 713	2 713	4.2516-02 2.310e-02	4.25Te-02		
			12	Argon (Ar)			0.0	0.0	0.0	0.0		
			13	Total			1.703e+05	1.703e+05	2504	2504		
			14									
			15									
		Process	Туре	Activated Ca	arbon Ir	j. 💌						
		<u>1</u> . Die	agrar	n <u>2</u> . Flue	Gas	<u>3</u> . Capital Co	ost <u>4</u> .0a	&M Cost 🖌	<u>5</u> . Total Cost	. /		

Mercury – Flue Gas result screen.

### **Major Flue Gas Components**

Each result is described briefly below.

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **Mercury Capital Cost Results**

This screen is only available for the Combustion (Boiler) plant type. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the water and carbon injection systems, both part of the overall mercury control option.

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6			<u>C</u> onfigure Plant	Set <u>P</u> ar	ame	ters <u>G</u> et Re	sults
		Ove <u>r</u> Plar	all Fuel <u>B</u> oiler <u>A</u> ir Preheater	NOx Control	cury	Image: Image shows a state of the	Prod. Igmt Stac <u>k</u>
<i>₿</i>			Mercury Removal Process Area Costs	Capital Cost (M\$)		Mercury Removal Plant Costs	Capital Cost (M\$)
ß		1	Spray Cooling Water	0.0	1	Process Facilities Capital	3.489e-02
- -		2	Sorbent Injection	0.0	2	General Facilities Capital	1.745e-03
		3	Sorbent Recycle	0.0	3	Eng. & Home Office Fees	3.489e-03
•		4	Additional Ductwork	0.0	4	Project Contingency Cost	5.234e-03
		5	Sorbent Disposal	0.0	5	Process Contingency Cost	1.745e-03
91		6	CEMS Upgrade	3.489e-02	6	Interest Charges (AFUDC)	2.246e-08
×2		7	Pulse-Jet Fabric Filter	0.0	7	Royalty Fees	0.0
<u>.</u>		8	Process Facilities Capital	3.489e-02	8	Preproduction (Startup) Cost	7.750e-03
		9			9	Inventory (Working) Capital	2.355e-04
		10			10	Total Capital Requirement (TCR)	5.509e-02
		11			11		
		12			12		
		13			13		
		14			14		
		15			15	Effective TCR	5.509e-02
		Pro	cess Type: Activated Carbon Inj.	v		Costs are in Constant 2005 dollars.	
			1. Diagram 🖌 2. Flue Gas 🗎 3	, Capital Cost		. O&M Cost / <u>5</u> . Total Cost /	

Mercury – Capital Cost result screen.

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

#### **Direct Capital Costs**

The direct capital costs described here apply to the various mercury control equipment added to the power plant. These controls may physically be part of other control technologies, but have their particular capital costs considered here.

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses. They are described in general below. The primary factors in the model that effect the capital cost of the base plant are the plant size, the amount of water injected, the amount of activated carbon injected, and the sulfur and moisture content of the coal.

- **Spray Cooling Water:** This capital cost area represents the materials and equipment necessary to inject water into the flue gas duct for the purpose of cooling the flue gas to a prerequisite temperature. Equipment includes water storage tanks, pumps, transport piping, injection grid with nozzles, and a control system. The direct capital cost is a function of the water flow rate.
- **Sorbent Injection:** This capital cost area represents the materials and equipment necessary to deliver the activated carbon into the flue gas. Equipment includes silo pneumatic loading system, storage silos, hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the sorbent flow rate.
- **Sorbent Recycle:** This capital cost area represents the materials and equipment necessary to recycle ash and activated carbon from the particulate collector back into the duct injection point. The purpose is to create a equilibrium state where the carbon is reintroduced to improve performance. Equipment includes hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the recycle rate of ash and spent sorbent.

NOTE: Sorbent recycling is a feature to be added in a future version of the IECM.

Additional Ductwork: This capital cost area represents materials and equipment for ductwork necessary beyond the other process areas. Extra ductwork may be required for difficult retrofit installations.

NOTE: Future versions of the IECM will include parameters to determine a capital cost for this area. The current version assumes no additional ductwork.

**Sorbent Disposal:** This capital cost area represents materials and equipment required to house and dispose the collected sorbent. Equipment includes hoppers, blowers, transport piping, and a control system. This is in excess of existing hoppers, tanks, and piping used for existing particulate collectors. The direct capital cost is determined by the incremental increase in collected solids in the particulate collector.

**CEMS Upgrade:** This capital cost area represents materials and equipment required to install a continuous emissions monitoring system (CEMS) upgrade. The direct capital cost is determined by the net electrical output of the power plant.

**Pulse-Jet Fabric Filter:** This capital costs area represents an upgrade to an existing cold-side ESP, where one section at the back end of the unit

is replaced with a pulse-jet fabric filter. This can be considered a pseudo-COHPAC. Equipment includes pulse-jet FF, filter bags, ductwork, dampers, and MCCs, instrumentation and PLC controls for baghouse operation. Equipment excludes ash removal system, power distribution and power supply, and distributed control system. The direct capital cost is a function of the flue gas flow rate and the air to cloth ratio of the fabric filter.

NOTE: The IECM currently does not support multiple particulate devices in the same configuration nor a modified cold-side ESP.

**Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

#### **Total Capital Costs**

- **Process Facilities Capital:** See definition above. This result is highlighted in yellow.
- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

**Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

**Effective TCR:** The TCR of the water and carbon injection controls that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the water and carbon injection system.

# Mercury O&M Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs related to the water and carbon injection systems, both part of the overall mercury control option. The variable O&M costs are calculated from the variable costs for carbon, water consumption and fly ash disposal (from the particulate control device). The fixed O&M costs are based on maintenance and labor costs

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<i>∰</i>			Variable Cost C	omponent	O&M Cost (M\$/yr)		Fix	ed Cost Component	O&M Cost (M\$/yr)
		1	Activated Carbon		0.0	1	Operating La	bor	5.272e-02
<u>중</u> 1		2	Water		0.0	2	Maintenance	Labor	2.826e-06
		3	Additional Waste Dispo	sal	0.0	3	Maintenance	Material	4.239e-06
		4	Electricity		1.578e-02	4	Admin. & Su	pport Labor	1.318e-02
		5	Total Variable Costs		1.578e-02	5	Total Fixed C	osts	6.591e-02
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	ľ		<u>1</u> . Diagram 🖌 <u>2</u> . I	lue Gas 🖌	<u>3</u> . Capital Cost	<u>}</u>	. O&M Cost	<u>5</u> . Total Cost	/

Mercury – O&M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

### **Variable Cost Components**

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Activated Carbon: This is the activated carbon cost for flue gas conditioning.

Water: This is the water cost for flue gas conditioning.

Additional Waste Disposal: This is the solid disposal cost per year for the flue gas conditioning. Only the removal of carbon from the particulate device is considered here.

- **Electricity:** This is the power utilization cost per year for the flue gas conditioning.
- **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

# **Mercury Total Cost Results**

This screen is only available for the Combustion (Boiler) plant type. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs related to the water and carbon injection systems, both part of the overall mercury control option.

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	Ove <u>r</u> all Plant	Fuel	Boiler	<u>A</u> ir Preheater	<u>N</u> Ox Control	Mercury	<u>T</u> SP <u>S</u> Control Co	02 C <u>O</u> 2 ntrol Captu	re By-Prod. Mgmt	Stac <u>k</u>
<i>≱</i> ∦ ₽			Cost (	Component		M\$/yr	\$/MWh	\$/ton Hg removed	Percent Total	
B		1 Annua	l Fixed Cost			6.591e-02	3.013e-02	0.0	73.43	
		2 Annua 3 Total A	il Variable Co Annual O&M	ost I Cost		1.568e-02 8.159e-02	7.167e-03 3.730e-02	0.0	17.47 90.90	
		4 Annua	lized Capital	Cost		8.167e-03	3.733e-03	0.0	9.099	
<u>~</u>		6		nualCost		0.3736-02	4.1036-02	0.0	100.0	
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	Process	Type: Act	tivated Car	bon Inj.	7		Costs are in C	onstant 2005 d	ollars.	
	<u>1</u> . Di	agram /	<u>2</u> . Flue C	Fas	3. Capital Co	ost <u>4</u> .0	&M Cost	<u>5</u> . Total Cost		

Mercury – Total Cost result screen.

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

### **Cost Component**

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# **Cold-Side ESP**

The **TSP Control**. Technology Navigation screens define and display flows and costs related to the particulate control technology. These screens are available only if the **Cold–Side ESP** TSP control technology is selected in the **Combustion** (Boiler) plant type configurations.

# **Cold-Side ESP Performance Inputs**

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for the performance of the Cold–Side ESP TSP control technology are entered on the **Performance** input screen. Many of the parameters are calculated by the IECM. Each parameter is described briefly below.

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111		1	Particulate Re:	moval Efficiency		%		99.75	M	0.0	100.0	calc	
		2	Actual SO3 R	emoval Efficiency		%		25.00		0.0	100.0	25.00	
		3											
		4	Collector Plate	e Spacing		inches		12.00		6.000	16.00	12.00	
		5	Specific Colle	ction Area	so	ff/1000 acfm		287.3	M	100.0	1000	calc	
		6	Plate Area per	r T-R Set	s	q ft/T-R set		2.375e+04		5000	5.000e+04	2.375e+04	
		7			_								
		8	Percent Water	r in ESP Discharge	_	%		0.0	M	0.0	100.0	calc	
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Ш		10	Cold-Side ESF	Power Requiremer	ıt	% MWg		0.2527	R	0.0	10.00	calc	
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Cold–Side ESP – Performance input screen.

ESPs consist of a series of parallel plates with rows of electrodes in between them and carry a high voltage of opposite polarity. As the particle laden flue gas enters the unit, the particles are charged by the electrodes and is attracted to the plates. At controlled intervals the plates are rapped which shakes the dust to a hopper below. However, some of the dust is re-entrained and carried to the next zone or out of the stack. Most ESPs use rigid collecting plates with shielded air pockets (baffles) through which ash falls into the hoppers after rapping.

The major design parameters which can significantly impact the total system capital cost are *gas flow volume* (which depends on the generating unit size), *SCA*, the collecting plate area per transformer-rectifier (T-R) set and the spacing between collector plates.

- **Particulate Removal Efficiency:** The calculated value determines the removal efficiency needed to comply with the specified particulate emission limit set earlier. This efficiency then determines the mass of particulate matter removed in the collector.
- Actual SO₃ Removal Efficiency: The default value is taken from the removal efficiency reported in the literature (references are below). This efficiency then determines the mass of SO₃ removed from the flue gas in the collector. For more information see also:
  - www.netl.doe.gov/publications/proceedings/98/98fg/hardman.pdf
  - www.netl.doe.gov/publications/proceedings/98/98fg/rubin.pdf
- **Collector Plate Spacing:** The collector plate spacing is typically 12 inches. The spacing is used to determine the specific collection area.
- **Specific Collection Area:** The specific collection area (SCA) is the ratio of the total plate area and flue gas volume. It sizes the ESP. The value is calculated from the removal efficiency, plate spacing, and the drift velocity. It is used to determine the capital cost and the total collection area required.
- **Plate Area per T-R Set:** This is the total surface area of one T-R set of plates. It is used to determine the total number of T-R sets needed and the capital costs.
- **Percent Water in ESP Discharge:** This is the water content of the collected fly ash. Fly ash disposed with bottom ash is assumed to be sluiced with water and dry otherwise. The occluded water in wet fly ash is difficult to remove, resulting in a rather high water content when the fly ash is mixed with bottom ash.
- **Cold-Side ESP Power Requirement:** The default calculation is based on the T-R set power consumption with estimates for auxiliary power requirements and electro-mechanical efficiencies of fan motors. The T-R set power consumption is a function of removal efficiency.

# **Cold-Side ESP Retrofit Cost Inputs**

This screen is only available for the Combustion (Boiler) plant type. Inputs for the capital costs of modifications to process areas to implement the Particulate control technology are entered on the **Retrofit Cost** input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for

each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

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Ж	Ш	1	<u>Capital</u> C	<u>Cost Process Area</u>									
8	Ш	2	Particulate Co	ollector		retro \$/new \$		1.000		0.0	10.00	1.000	
B	Ш	3	Ductwork			retro \$/new \$		1.000		0.0	10.00	1.000	
	Ш	4	Fly Ash Han	dling		retro \$/new \$		1.000		0.0	10.00	1.000	
E.	Ш	5	Differential II	) Fan		retro \$/new \$		1.000		0.0	10.00	1.000	
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Cold–Side ESP – Retrofit Cost input screen.

Each parameter is described briefly below.

## **Capital Cost Process Area**

- **Particulate Collector:** This area covers the material and labor, flange to flange, for the equipment and labor cost for installation of the entire collection system.
- **Ductwork:** This area includes the material and labor for the ductwork needed to distribute flue gas to the inlet flange, and from the outlet flange to a common duct leading to the suction side of the ID fan.
- Fly Ash Handling: The complete fly ash handling cost includes the conveyor system and ash storage silos.
- **Differential ID Fan:** The complete cost of the ID fan and motor due to the pressure loss that results from particulate collectors.

# **Cold-Side ESP Capital Cost Inputs**

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for the capital costs of particulate control technology are entered on the **Capital Cost** input screen.

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		Title		Units	Unc	Value	Calc	Min	Max	Default	
Ш	1	Construction Time		years		3.000		0.2500	10.00	3.000	
Ш	2										
	3	General Facilities Capital		%PFC		1.000		0.0	50.00	1.000	
	4	Engineering & Home Offic	e Fees	%PFC		5.000		0.0	50.00	5.000	
	5	Project Contingency Cost		%PFC		20.00		0.0	100.0	20.00	
	6	Process Contingency Cos	;	%PFC		0.0	×	0.0	100.0	calc	
	7	Royalty Fees		%PFC		0.0		0.0	10.00	0.0	
	8										
	9	Pre-Production Cos	ts								
	10	Months of Fixed O&M		months		1.000		0.0	12.00	1.000	
	11	Months of Variable O&M		months		1.000		0.0	12.00	1.000	
	12	Misc. Capital Cost		%TPI		2.000		0.0	10.00	2.000	
	13										
	14	Inventory Capital		%TPC		0.5000		0.0	10.00	0.5000	
	15										
	16										
	17										
	18	TCR Recovery Factor		%		100.0		0.0	100.0	100.0	
	Proc	ess Type: Cold-Side E	SP	~							
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Cold–Side ESP – Capital Cost input screen.

The necessary capital cost input parameters associated with the electrostatic precipitator control technology are shown on this input screen.

Indirect Capital Costs: Costs that are indirectly applied to the technology are based on the process facilities cost. Each of the cost factors below is expressed as a percentage of the process facilities cost, and is entered on this screen. Each parameter is described briefly below.

- **Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).
- **General Facilities Capital (GFC):** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

- **Pre-Production Costs :** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during startup. These are typically applied to the O&M costs over a specified period of time (months)The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.
  - **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
  - **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
  - **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a cold-side ESP that has been paid off.

# Cold-Side ESP O&M Cost Inputs

This screen is only available for the **Combustion (Boiler)** plant type.

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			Title		Units	Unc	Value	Calc	Min	Max	Default
[	1	Waste Dispo:	sal Cost		\$/ton		13.86	V	0.0	100.0	calc
	2	Electricity Pri	ce (Base Plant)		\$/MWh		41.12		0.0	200.0	calc
	3										
	4	Number of Op	perating Jobs		jobs/shift		0.9700		0.0	30.00	0.9700
	5	Number of Op	perating Shifts		shifts/day		4.750		0.0	10.00	4.750
	6	Operating Lat	bor Rate		\$/hr		24.82		0.0	100.0	24.82
	7										
-	8	Total Mainter	nance Cost		%TPC		1.770		0.0	10.00	calc
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-	10	Administrativ	re & Support C	ost	% total labor		30.00		0.0	100.0	30.00
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Cold–Side ESP – O&M Cost screen input.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Inputs for the operation and maintenance costs of the particulate control technology are entered on this screen.

- **Waste Disposal Cost:** This is the disposal cost for the particulate control system.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as combustion boiler and an air preheater.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work ( 3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- **Maint. Cost Allocated to Labor:** Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

# **Cold-Side ESP Diagram**

This screen is only available for the Combustion (Boiler) plant type. The **Diagram** result screen displays an icon for the particulate control technology selected and values for major flows in and out of it.

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		Overall Fuel Boiler Air Plant Fuel Boiler	<u>N</u> Ox Control Mercury <u>T</u> SP Control	SO2 CO2 By-P Control Capture Mg	rod. Stac <u>k</u> gmt
		Temperature In (deg. F) 175.0   Flue Gas In (acfm) 1.392e+06   Fly Ash In (ton/hr) 26.87   Mercury In (lb/hr) 3.533e-02		Temperature Out (deg. F) Flue Gas Out (acfm) Fly Ash Out (ton/hr) Mercury Out (lb/hr) Ash Removal (%) SO3 Removal (%) Mercury Removal (%)	175.0 1.346e+06 6.631e-02 3.533e-03 99.75 25.00 90.00
		Stuice Water (ton/hr) 0.0 —		Dry Ash (ton/hr) • Wet Ash (ton/hr)	26.80
		Process Type: Cold-Side ESP	3. Capital Cost 🖌 4. O&M Cost	🖌 <u>5</u> . Total Cost 🖌	

Cold–Side ESP – Diagram

Each result is described briefly below:

## Flue Gas Entering ESP

- **Temperature In:** Temperature of the flue gas entering the particulate control technology. This is determined by the flue gas outlet temperature of the module upstream of the air preheater (e.g., the air preheater).
- **Flue Gas In:** Volumetric flow rate of the flue gas entering the particulate control technology, based on the flue gas inlet temperature and atmospheric pressure.
- **Fly Ash In:** Total solids mass flow rate in the flue gas entering the air preheater. This is determined by the solids exiting the module upstream of the particulate control technology (e.g., the air preheater).
- **Mercury In:** Total mass of mercury entering the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

### Flue Gas Exiting ESP

**Temperature Out:** Temperature of the flue gas exiting the particulate control technology. The model currently does not alter this temperature through the particulate control technology.

- **Flue Gas Out:** Volumetric flow rate of the flue gas exiting the particulate control technology, based on the flue gas exit temperature and atmospheric pressure.
- **Fly Ash Out:** Total solids mass flow rate in the flue gas exiting the particulate control technology. This is a function of the ash content of the inlet flue gas and the ash removal efficiency performance input parameter.
- **Mercury Out:** Total mass of mercury exiting the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

### **ESP** Performance

- **Ash Removal:** Ash removal efficiency of the particulate control technology. This is a function of the ash emission constraint and the inlet ash mass flow rate.
- **SO₃ Removal:** Percent of SO₃ in the flue gas removed from the particulate control technology. The SO₃ is assumed to combine with  $H_2O$  and leave with the ash solids as a sulfate (in the form of  $H_2SO_4$ ).
- **Mercury Removal:** Percent of the total mercury removed from the particulate control technology. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

# **Collected Fly Ash**

- **Dry Ash:** Total mass flow rate of the solids removed from the ESP. This is a function of the solids content in the flue gas and the particulate removal efficiency of the ESP. The value is given on a dry basis.
- **Sluice Water:** Water added to the dry fly ash. This water is added for transportation purposes.
- Wet Ash: Total mass flow rate of the solids removed for waste management. This includes dry fly ash and sluice water. The value is given on a wet basis.

# **Cold-Side ESP Flue Gas Results**

This screen is only available for the **Combustion (Boiler)** plant type. The Flue **Gas** result screen displays a table of quantities of flue gas components entering and exiting the Particulate Control Technology. For each component, quantities are given in both moles and mass per hour.

<u>C</u>	oni	figure Plant 📔 Se	t <u>P</u> arameter	s	<u>(</u>	Get Results	
Overall P <u>l</u> ant	F	uel <u>B</u> oiler <u>A</u> ir <u>N</u> Ox Preheater Control	Mercury	<u>T</u> SP Control Cor	D2 C <u>O</u> 2 ntrol Captu	re <u>M</u> gmt	Stac <u>k</u>
		Major Flue Gas Components	Flue Gas In (b-moles/hr)	Flue Gas Out (b-moles/hr)	Flue Gas In (ton/hr)	Flue Gas Out (ton/hr)	
	1	Nitrogen (N2)	1.266e+05	1.266e+05	1773	1773	
	2	Oxygen (O2)	9372	9372	149.9	149.9	
Ī	3	Water Vapor (H2O)	2.369e+04	1.776e+04	213.4	160.1	
Ī	4	Carbon Dioxide (CO2)	2.050e+04	2.050e+04	451.1	451.1	
	5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	
	6	Hydrochloric Acid (HCl)	5.643	5.643	0.1029	0.1029	
Ī	7	Sulfur Dioxide (SO2)	41.24	41.24	1.321	1.321	
Ī	8	Sulfuric Acid (equivalent SO3)	8.639e-02	6.479e-02	3.458e-03	2.594e-03	
Ī	9	Nitric Oxide (NO)	35.11	35.11	0.5268	0.5268	
	10	Nitrogen Dioxide (NO2)	1.848	1.848	4.251e-02	4.251e-02	
	11	Ammonia (NH3)	2.713	2.713	2.310e-02	2.310e-02	
	12	Argon (Ar)	0.0	0.0	0.0	0.0	
	13	Total	1.802e+05	1.743e+05	2589	2536	
	14						
	15						

Cold–Side ESP – Flue Gas results screen.

Each result is described briefly below:

### **Major Flue Gas Components**

Nitrogen (N2): Total mass of nitrogen.

Oxygen (O2): Total mass of oxygen.

Water Vapor (H2O): Total mass of water vapor.

Carbon Dioxide (CO2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.

Ammonia (NH3): Total mass of Ammonia.

Argon (Ar): Total mass of Argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **Cold–Side ESP Capital Cost Results**

This screen is only available for the **Combustion (Boiler)** plant type. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the particulate control technology.



Cold-Side ESP — Capital Costs results screen.

# **Direct Capital Costs**

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the cold-side ESP are the specific and total collection areas of the T-R plate sets, and the flue gas flow rate through the ESP. The primary model factors that effect the capital costs of the fabric filter are the fabric filter type, the air to cloth ratio, the number of bags and compartments, and the flue gas flow rate through the fabric filter.

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. The parameters are described below.

- **Particulate Collector:** This area covers the material and labor, flange to flange, for the equipment and labor cost for installation of the entire collection system.
- **Ductwork:** This area includes the material and labor for the ductwork needed to distribute flue gas to the inlet flange, and from the outlet flange to a common duct leading to the suction side of the ID fan.
- Fly Ash Handling: The complete fly ash handling cost includes the conveyor system and ash storage silos.
- **Differential ID Fan:** The complete cost of the ID fan and motor due to the pressure loss that results from particulate collectors.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

### **Total Capital Costs**

- Process Facilities Capital: (see definition above)
- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the cold-side ESP that is used in determining the total power plant cost. The effective TCR is determined by the **TCR Recovery Factor** for the cold-side ESP.

# Cold–Side ESP O&M Cost Results

This screen is only available for the **Combustion (Boiler)** plant type. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the Cold–Side ESP TSP particulate control technology.
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Cold–Side ESP – O&M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

#### Variable Cost Component

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

- **Solid Waste Disposal:** Total cost to dispose the collected fly ash. This does not consider by-product ash sold in commerce.
- **Power:** Cost of power consumption of the particulate control technology. This is a function of the flue gas flow rate, ash removal efficiency and the type of coal (ash properties).
- **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

#### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.

- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- **Admin. & Support Labor:** The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

## **Cold-Side ESP Total Cost Results**

This screen is only available for the **Combustion (Boiler)** plant type. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the Cold–Side ESP TSP Control technology.

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P			2	Annual	Variable C	ost		1.114	0.5092	17.67	22.35	
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Cold–Side ESP – Total Cost result screen.

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

#### **Cost Component**

**Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# **Fabric Filter**

The **TSPControl** Technology Navigation Tab contains screens that design and display flows and costs related to the particulate control technology. Shown in the Combustion (Boiler) plant type configurations.

## **Fabric Filter Configuration**

This screen is only available for the Combustion (Boiler) plant type.

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		Title	Units	Unc	Value	Calc	Min	Max	Default	
I	1	Fabric Filter Type			RG 🔻		Menu	Menu	RG	
I	2	Reverse Gas (RG)								
	3	Reverse Gas with Sonic (RG $+$ S)								
I	4	Shake and Deflate (Sh + D)								
I	5	Pulse-jet (PJ)								
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	Pro	ess Type: Fabric Filter	-							

Fabric Filter – Configuration input screen.

#### **Fabric Filter Type**

Fabric filters consist of a large number of long tubular filter bags arranged in parallel flow paths. As the ash-laden flue gas passes through these filters, much of the particulate matter is removed. Ash accumulated on the bags is removed periodically by various methods of cleaning. Choose the cleaning method in the **Config.** input screen. The available methods are:

- Reverse Gas (RG)
- Reverse Gas with Sonic (RG + S)

- Shake and Deflate (Sh + D)
- Pulse-jet (PJ)

# **Fabric Filter Performance Inputs**

This screen is only available for the Combustion (Boiler) plant type.

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	5	Number of Bag	zhouse Units		number		2	M	Menu	Menu	calc	
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	9	Bag Diameter			feet		1.000		0.0	2.000	1.000	
	10	Bag Life			years	?	4.000		3.000	5.000	calc	
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	12	Air to Cloth R	atio		acfm/sq ft	?	1.800	M	1.500	4.000	calc	
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	15	Percent Water	in Fabric Filte	r Disc	%		0.0	M	0.0	100.0	calc	
	16											
	17	Fabric Filter Po	ower Requirem	lent	% MWg		0.3362	Ľ	0.0	10.00	calc	
	18											
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Fabric Filter – Performance input screen.

The baghouse system is very efficient in removing particulate matter from the flue gas. It's model design is simple, requiring few parameters to characterize its effects on the overall performance of the plant. For properly designed fabric filters, the size of the system is independent of the removal efficiency.

Although the performance is determined by very few parameters, there are several design parameters necessary to determine the cost. These factors are also determined in this section. The major design parameters that can significantly impact the total system cost of the fabric filter are *gas flow volume* (which depends on the generating unit size), *A/C ratio*, the *flange-to-flange pressure drop* in the baghouse and the *bag life*.

- **Particulate Removal Efficiency:** The calculated removal is set to comply with the particulate emission limit set earlier. The mass removed is then determined. If you select a spray dryer, the particulate removal efficiency applies to the combined mass of flyash and sulfur-laden wastes. This input is highlighted in blue.
- Actual SO₃ Removal Efficiency: The default value is taken from the removal efficiency reported in the literature (references are below). This efficiency then determines the mass of SO₃ removed from the flue gas in the collector. For more information see also:
  - www.netl.doe.gov/publications/proceedings/98/98fg/hardman.pdf
  - www.netl.doe.gov/publications/proceedings/98/98fg/rubin.pdf

- **Solids Loading Out**: This is the fabric filter output loading. It is an average value based on typical fabric filter units. The value is used to determine the particulate removal efficiency.
- **Number of Baghouse Units:** This is the number of baghouse units. The value is based on the gross plant size. The value must be an integer. Each unit contains several compartments. It is used to calculate the capital cost of the baghouse.
- **Number of Compartments per Unit:** This parameter specifies the average number of compartments used per baghouse unit. It is used to calculate the capital cost of the baghouse.
- **Number of Bags per Compartment:** The number of individual bags per compartment is calculated by comparing the required bag surface area to the bag dimensions and the total number of compartments. It is used to calculate the capital cost of the baghouse.
- **Bag Length:** Bag length generally fall into two size categories: 30-36 ft or 20 -22 ft in length. It is based on the fabric filter type and used to calculate the capital cost of the baghouse.
- **Bag Diameter:** Bags are generally between 2/3 and 1 foot in diameter. The value is based on the fabric filter type and used to calculate the capital cost of the baghouse.
- **Bag Life:** Bag life is typically between 3-5 years. The bag life values are dependent on the fabric filter type and are used to calculate the cost of the baghouse.
- **Air to Cloth Ratio:** The Air to Cloth ratio is the most important baghouse parameter. It is the ratio of volumetric flue gas flow rate and total bag cloth area. The calculated value is a function of fabric filter type. It is used to determine the cost and power use of the baghouse.
- **Total Pressure Drop across Fabric Filter:** Baghouse pressure drop (flange-to-flange) is caused by pressure losses in gas flow as it moves through the bag fabric and dust cake. Typical values range from 6 to 8 in.  $H_2O$  and depend on the baghouse type selected. The value affects the power consumption.
- **Percent Water in Fabric Filter Discharge:** This is the water content of the collected fly ash. Fly ash disposed with bottom ash is assumed to be sluiced with water and dry otherwise. The occluded water in wet fly ash is difficult to remove, resulting in a rather high water content when the fly ash is mixed with bottom ash.
- **Fabric Filter Power Requirement:** The default calculation is based on the air-to-cloth ratio and the flue gas flow rate. The power accounts for the auxiliary power requirements and electro-mechanical efficiencies of fan motors.

### **Fabric Filter Retrofit Inputs**

This screen is only available for the Combustion (Boiler) plant type. Inputs for the capital costs of modifications to process areas to implement the Particulate control technology are entered on the **Retrofit Cost** input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment

installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

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Fabric Filter – Retrofit Cost input screen.

#### **Capital Cost Process Area**

- **Particulate Collector:** This is the cost for the collecting equipment, based on actual vendor prices. Included in the cost are the mechanical equipment and labor, particulate removal system, alternate cleaning system, gas conditioning system, structural supports, electrical, and instrumentation.
- **Ductwork:** This is the cost of all the mechanical, electrical, and supports of the ductwork to and from the collector.
- **Fly Ash Handling:** This is the cost of all the mechanical, conveyors, storage, and electrical portions of the ash handling system. The costs are based on actual vendor prices.
- **Differential ID Fan:** This area includes the additional cost of the ID fan and the motor due to the pressure loss that results from the particulate

collectors. Also included are the erection, piping, electrical, and foundation costs.

### **Fabric Filter Capital Cost Inputs**

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R		3	General Faciliti	ies Capital	%PFC		1.000		0.0	50.00	1.000	
		4	Engineering &	Home Office Fees	%PFC		5.000		0.0	50.00	5.000	
<u>B</u>		5	Project Contin	gency Cost	%PFC		20.00		0.0	100.0	20.00	
		6	Process Contin	ngency Cost	%PFC		0.0		0.0	100.0	calc	
		7	Royalty Fees		%PFC		0.0		0.0	10.00	0.0	
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<u>¥</u>		9	Pre-Pro	duction Costs								
<b>?</b>		10	Months of Fix	ed O&M	months		1.000		0.0	12.00	1.000	
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This screen is only available for the Combustion (Boiler) plant type.

Fabric Filter – Capital Cost input screen.

The necessary capital cost input parameters associated with the fabric filter control technology are shown on this input screen (no distinction is made between the various types of fabric filtersEach parameter is described briefly below.

Indirect Capital Costs: Costs that are indirectly applied to the technology are based on the process facilities cost. Each of the cost factors below is expressed as a percentage of the process facilities cost, and is entered on this screen. Each parameter is described briefly below.

- **Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).
- **General Facilities Capital (GFC):** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.

- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months)The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.
  - Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
  - **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
  - **Misc. Capital Costs:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

### Fabric Filter O&M Cost Inputs

This screen is only available for the Combustion (Boiler) plant type.

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Г		Title		Units	Unc	Value	Calc	Min	Max	Default	
	1	Fabric Filter Bag Cost		\$/bag		104.7		0.0	150.0	calc	
	2	Waste Disposal Cost		\$/ton		13.86	M	0.0	30.00	calc	
	3	Electricity Price (Base Plant)		\$/MWh		41.12		0.0	200.0	calc	
	4										
	5	Number of Operating Jobs		jobs/shift		1.330		0.0	30.00	1.330	
	6	Number of Operating Shifts		shifts/day		4.750		0.0	10.00	4.750	
	7	Operating Labor Rate		\$/hr		24.82		0.0	100.0	24.82	
	8										
	9	Total Maintenance Cost		%TPC		1.132		0.0	10.00	calc	
	10	Maint. Cost Allocated to Lab	or	% total		40.00		0.0	100.0	40.00	
	11	Administrative & Support Co	ost	% total labor		30.00		0.0	100.0	30.00	
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Fabric Filter – O&M Cost input screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

- **Fabric Filter Bag Cost:** This is the cost of a fabric filter bag as used for the fabric filter technology.
- **Waste Disposal Cost:** This is the disposal cost for the particulate control system.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work ( 3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

#### **Operating Labor Rate:**

- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- **Maint. Cost Allocated to Labor:** Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

### **Fabric Filter Diagram**

This screen is only available for the Combustion (Boiler) plant type. The **Diagram** result screen displays an icon for the **Fabric Filter** particulate control technology selected and values for major flows in and out of it.



Fabric Filter – Diagram

Each result is described briefly below

### Flue Gas Entering Filter

- **Temperature In:** Temperature of the flue gas entering the particulate control technology. This is determined by the flue gas outlet temperature of the module upstream of the air preheater (e.g., the air preheater).
- **Flue Gas In:** Volumetric flow rate of the flue gas entering the particulate control technology, based on the flue gas inlet temperature and atmospheric pressure.
- **Fly Ash In:** Total solids mass flow rate in the flue gas entering the air preheater. This is determined by the solids exiting the module upstream of the particulate control technology (e.g., the air preheater).
- **Mercury In:** Total mass of mercury entering the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

#### Flue Gas Exiting Filter

**Temperature Out:** Temperature of the flue gas exiting the particulate control technology. The model currently does not alter this temperature through the particulate control technology.

- **Flue Gas Out:** Volumetric flow rate of the flue gas exiting the particulate control technology, based on the flue gas exit temperature and atmospheric pressure.
- **Fly Ash Out:** Total solids mass flow rate in the flue gas exiting the particulate control technology. This is a function of the ash content of the inlet flue gas and the ash removal efficiency performance input parameter.
- **Mercury Out:** Total mass of mercury exiting the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

#### **Fabric Filter Performance**

- **Ash Removal:** Ash removal efficiency of the fabric filter technology. This is a function of the ash emission constraint and the inlet ash mass flow rate.
- **SO3 Removal:** Percent of  $SO_3$  in the flue gas removed from the particulate control technology. The  $SO_3$  is assumed to combine with  $H_2O$  and leave with the ash solids as a sulfate (in the form of  $H_2SO_4$ ).
- **Mercury Removal:** Percent of the total mercury removed from the particulate control technology. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

### **Collected Fly Ash**

- **Dry Ash:** Total mass flow rate of the solids removed from the fabric filter. This is a function of the solids content in the flue gas and the particulate removal efficiency of the fabric filter. The value is given on a dry basis.
- **Sluice Water:** Water added to the dry fly ash. This water is added for transportation purposes.
- Wet Ash: Total mass flow rate of the solids removed for waste management. This includes dry fly ash and sluice water. The value is given on a wet basis.

### **Fabric Filter Flue Gas Results**

This screen is only available for the Combustion (Boiler) plant type. The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the Particulate Control Technology. For each component, quantities are given in both moles and mass per hour.

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Overall Plant	F	<u>u</u> el <u>B</u> oiler <u>Air</u> <u>N</u> Ox Preheater Control	Mercury	TSP Sontrol Cor	D2 C <u>O</u> 2 ntro1 Captu	By-Prod. re <u>M</u> gmt	Stac <u>k</u>
		Major Flue Gas Components	Flue Gas In (b-moles/hr)	Flue Gas Out (b-moles/hr)	Flue Gas In (ton/hr)	Flue Gas Out (ton/hr)	
-	1	Nitrogen (N2)	1.266e+05	1.266e+05	1773	1773	
-	2	Oxygen (O2)	9372	9372	149.9	149.9	
Ī	3	Water Vapor (H2O)	2.369e+04	2369	213.4	21.34	
Ĩ	4	Carbon Dioxide (CO2)	2.050e+04	2.050e+04	451.1	451.1	
	5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	
	6	Hydrochloric Acid (HCl)	5.643	5.643	0.1029	0.1029	
Ĩ	7	Sulfur Dioxide (SO2)	41.24	41.24	1.321	1.321	
Ĩ	8	Sulfuric Acid (equivalent SO3)	8.639e-02	8.639e-03	3.458e-03	3.458e-04	
	9	Nitric Oxide (NO)	35.11	35.11	0.5268	0.5268	
	10	Nitrogen Dioxide (NO2)	1.848	1.848	4.251e-02	4.251e-02	
	11	Ammonia (NH3)	2.713	2.713	2.310e-02	2.310e-02	
	12	Argon (Ar)	0.0	0.0	0.0	0.0	
	13	Total	1.802e+05	1.589e+05	2589	2397	
	14						
	15						

Fabric Filter – Flue Gas result screen.

Each result is described briefly below

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃):Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

### **Fabric Filter Capital Cost Results**

This screen is only available for the Combustion (Boiler) plant type. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the particulate control technology.

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		Over Plar	all nt	Fu	e1	Í	<u>B</u> oiler	Ì	<u>A</u> ir Prehe	r ater	<u>N</u> Ox Contr		<u>vI</u> ero	cury	<u>T</u> SP Control	<u>S</u> O2 Control	CO: Captu	2 .are	By-Pro Mgm	t.	Stac <u>k</u>
			]	abric	Filte	r P:	rocess	Ar	ea Cos	its	Capi (	tal Co: M\$)	st		Fab	ric Filter P	lant Cos	ts	(	Capital (M	. Cost \$)
I		1	Colle	ctor							2	5.87		1	Process Faci	lities Capit	ગ			31.1	4
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Ш		3	Fly A	sh H	andlir	ng					4	.324		3	Eng. & Hom	e Office Fe	es			1.55	57
I		4	Diffe	entia	l						0.	2488		4	Project Cont	ingency Co	ost			6.22	29
Ш		5	Proc	ss Fa	cilitie	s C	apital				3	1.14		5	Process Con	tingency C	ost			0.0	)
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II		7											-1	7	Royalty Fee:	s				0.0	)
II		8											-1	8	Preproductio	on (Startup)	Cost			0.86	85
II		9											-1	9	Inventory (V	Vorking) C	apital			0.19	62
II		10											-1	10	Total Capital	l Requireme	ent (TCR)	)		44.4	19
11	П	11											_	11							
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		13									_		-1	13							
I	Π	14											-1	14		_					_
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		Pre	cess	Гуре:	E	ıbri	c Filt	er.				-			Costs are	e in Consta	nt 2005 (	dollar	s.		

Fabric Filter – Capital Cost result screen.

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

#### **Direct Capital Costs**

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the cold-side ESP are the specific and total collection areas of the T-R plate sets, and the flue gas flow rate through the ESP. The primary model factors that effect the capital costs of the fabric filter are the fabric filter type, the air to cloth ratio, the number of bags and compartments, and the flue gas flow rate through the fabric filter.

- **Collector:** This area covers the material and labor, flange to flange, for the equipment and labor cost for installation of the entire collection system.
- **Ductwork:** This area includes the material and labor for the ductwork needed to distribute flue gas to the inlet flange, and from the outlet flange to a common duct leading to the suction side of the ID fan.
- Fly Ash Handling: The complete fly ash handling cost includes the conveyor system and ash storage silos.
- **Differential:** The complete cost of the ID fan and motor due to the pressure loss that results from particulate collectors.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

#### **Total Capital Costs**

Process Facilities Capital: (see definition above)

- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital**: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the fabric filter that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the fabric filter.

### Fabric Filter O&M Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the particulate control technology.

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<b>3</b>				Va	uriable	e Co	st Con	фон	ient		0&1 (M	VI Cos \$/yr)	t		Fi	xed Cost Co	mponent			O&M (M\$	i Cost /yr)	
e.		1	Soli	d Wast	te Dis	pos	1				0.8	3729		1	Operating La	abor				0.40	007	
<b>P</b>		2	Elec	tricity							0.6	5164		2	Maintenanc	e Labor				0.13	777	
	II	3	Tot	al Varia	ible C	osts					1.	389		3	Maintenanc	e Material				0.26	665	
	II	4	_										-1	4	Admin. & Sı	ipport Labo	r			0.13	735	
$\geq$	II	5	_										-1	5	Total Fixed (	Costs				1.0	18	
₿	II	6	-										-1	6								
?	II	7	_										-1	7								
-11	II	8	-										-1	8								
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Fabric Filter – O&M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

#### Variable Cost Component

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

- **Solid Waste Disposal:** Total cost to dispose the collected fly ash. This does not consider by-product ash sold in commerce.
- **Electricity:** Cost of power consumption of the particulate control technology. This is a function of the flue gas flow rate, ash removal efficiency and the type of coal (ash properties).
- **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

#### **Fixed Cost Component**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.

- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

# **Fabric Filter Total Cost Results**

This screen is only available for the Combustion (Boiler) plant type. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the Particulate Control technology. The result categories are the same for both the Cold-Side ESP and the Fabric Filter

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			Cos	т Сонфонент		M\$/yr	\$/MWh	\$/ton solids removed	Percent Total	
		1	Annual Fixed Co	st		1.018	0.4669	16.05	11.33	
III		2	Annual Variable	Cost		1.389	0.6370	21.90	15.45	
ill		3	Total Annual Oa	ZM Cost		2.408	1.104	37.94	26.78	
		4	Annualized Capi	tai Cost		8 997	4123	103.8	13.22	
		6	1 oral Dovember	initial CODE		0.002	4.120	141.1	100.0	
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	Process	Туре	Fabric Filte	ſ	Y	1	Costs are in C	onstant 2005 d	ollars.	
	<u>1</u> . Dia	agran	n <u>2</u> .Flu	e Gas	3. Capital C	ost 🖌 <u>4</u> .C	&M Cost	<u>5</u> . Total Cost		

Fabric Filter – Total Cost result screen.

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

### **Cost Component**

**Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost**: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Annual Cost**: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow. The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

# Wet FGD

The **SO2 Control** Technology Navigation contains screens that address postcombustion air pollution technologies for Sulfur Dioxide. The model includes options for a Wet FGD. The screens are available if this SO₂ control technology has been selected in **Configure Plant** for the Combustion (Boiler) plant type.

### Wet FGD Configuration

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for configuration of the Wet FGD  $SO_2$  control technology are entered on the **Config** input screen.

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	Configure I	Plant			Set Par	amet	ers			Get Re:	sults	
Ove <u>r</u> ali Plant	Fuel	<u>B</u> ase Plant	Emissi Constr	on aint	Mercury	<u>N</u> Cor	Ox atro1 C	<u>T</u> SP ontrol	<u>S</u> O2 Control	C <u>C</u> Capt	2 By-1 ture M;	Prod gmt
		Title			Units	Unc	Value	Calc	Min	Max	Default	
1	Reagent						Limestor	-	Menu	Menu	Limestone	
2						_		_				
3	Flue Gas Byp	ass Control				_	No Bypa:	-	Menu	Menu	No Bypass	
4						_		_				
						_		-				
7						-						
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Wet FGD – Config. Input screen (no bypass). .

Each parameter is described briefly below.

#### Reagent

For Wet FGD systems, the choice of reagent affects nearly all of the performance and economic parameters of the FGD. Three choices are available:

- **Limestone:** Limestone with Forced Oxidation—A limestone slurry is used in an open spray tower with in-situ oxidation to remove SO₂ and form a gypsum sludge. The main advantages as compared to conventional systems are easier dewatering, more economical disposal of scrubber products, and decreased scaling on tower walls.
- **Limestone with Additives**: Limestone with Dibasic Acid Additive— Dibasic acid (DBA) is added to the Limestone to act as a buffer/catalyst in the open spray tower. The main advantages are increased SO₂ removal and decreased liquid to gas ratio.
- **Lime:** Magnesium Enhanced Lime System—A magnesium sulfite and lime slurry (maglime) is used to remove SO₂ and form a precipitate high in calcium sulfite. The high alkalinity of the maglime slurry allows very high SO₂ removal. However, the reagent cost is also higher and solid waste is not easily disposed.

### Flue Gas Bypass Control

This popup selection menu controls whether or not a portion of the inlet flue gas may bypass the scrubber and recombine with the treated flue gas. Bypass allows the scrubber to operate at full efficiency while allowing some of the flue gas to go untreated. Two choices are available:

**No Bypass:** This option forces the entire flue gas to pass through the scrubber. This is the default option.

	<u>C</u> onfigure Plant		Set Par	amet	ers	Ĩ	<u>G</u> et Results		
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	Title		Units	Unc	Value	Calc	Min	Max	Default
1	Reagent				LS w/ Ac •		Menu	Menu	Limestone
2									
3	Flue Gas Bypass Control				Bypass 🔻		Menu	Menu	No Bypass
4	Maximum SO2 Removal Efficiency	r	%		98.00	_	0.0	99.00	98.00
5	Overall SO2 Removal Efficiency		%		80.66		30.00	99.00	calc
6	(Required by SO2 emis. constrain	ut)				_			
7	Scrubber SO2 Removal Efficiency		%	_	98.00	M	30.00	99.00	calc
8	Minimum Bypass		%		0.0	_	0.0	100.0	0.0
9	Allowable Bypass		%		17.69		0.0	100.0	calc
10	Actual Bypass		%		17.69	M	0.0	100.0	calc
11		_							
12		_							
13		_		_					
14		_		_					
15		_		_					
16		_		_					
17		_		_					
18									

**Bypass**: This option allows for the possibility of a portion of the flue gas to bypass the scrubber. The amount of bypass is controlled by several additional input parameters described below.

Wet FGD – Config. input screen (with bypass).

The following five choices are available for flue gas bypass:

Maximum SO₂ Removal Efficiency: This parameters specifies the maximum efficiency possible for the absorber on an annual average

basis. The value is used as a limit in calculating the actual  $SO_2$  removal efficiency for compliance.

- **Overall SO₂ Removal Efficiency:** This value is the SO₂ removal efficiency required for the entire power plant to meet the SO₂ emission constraint set earlier. It is used to determine the actual flue gas bypass above.
- Scrubber  $SO_2$  Removal Efficiency: This is the actual removal efficiency of the scrubber alone. It is a function of the  $SO_2$  emission constraint and the actual flue gas bypass. This value is also shown on the next input screen.
- **Minimum Bypass:** This specifies the trigger point for allowing flue gas to bypass the scrubber. No bypass is allowed until the allowable amount reaches the minimum level set by this parameter.
- **Allowable Bypass**: This is the amount of flue gas that is allowed to bypass the scrubber, based on the actual and maximum performance of the SO₂ removal. It is provided for reference only. The model determines the bypass that produces the maximum SO₂ removal and compares this potential bypass with the minimum bypass value specified above. Bypass is only allowed when the potential bypass value exceeds the minimum bypass value.
- Actual Bypass: This displays the actual bypass being used in the model. It is based on all of the above and is provided for reference purposes only.

### Wet FGD Performance Inputs

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for performance of the Wet FGD  $SO_2$  control technology are entered on the **Performance** input screen. Each parameter is described briefly below.

ondice	Configure Plant	Sat Doro	mat	a*/C	T		Get Dec	aulte	
Ove <u>r</u> all Plant	Fuel Base Plant Merc	ury <u>N</u> Ox Control	T: Cor	SP Score	D2 ntro1	CO2 By-Prod. Capture Mgmt Stac <u>k</u>			
	Title	Units	Unc	Value	Calc	Min	Max	Default	
1	Maximum SO2 Removal Efficiency	%		98.00		0.0	99.00	98.00	
2	Scrubber SO2 Removal Efficiency	%		80.66		30.00	99.00	calc	
3	Scrubber SO3 Removal Efficiency	%		50.00		0.0	100.0	50.00	
4	Particulate Removal Efficiency	%		50.00		0.0	100.0	50.00	
5	Absorber Capacity	% acfm		100.0		0.0	200.0	100.0	
6	Number of Operating Absorbers	integer		1	M	Menu	Menu	calc	
7	Number of Spare Absorbers	integer		• 0		Menu	Menu	0	
8	Liquid-to-Gas Ratio	gpm/1000 acfm		90.00	M	90.00	200.0	calc	
9	Reagent Stoichiometry	mol Ca/mol S rem		1.030	M	1.000	3.000	calc	
1	Reagent Purity	wt %		92.40	M	80.00	100.0	calc	
1	Reagent Moisture Content	wt %		0.0	M	0.0	5.000	calc	
1:	Total Pressure Drop Across FGD	in H2O gauge		10.00	M	0.0	20.00	calc	
1:	Temperature Rise Across ID Fan	°F (delta)		14.00		0.0	25.00	14.00	
1.	Gas Temperature Exiting Scrubber	°F		129.3	V	115.0	185.0	calc	
1:	Gas Temperature Exiting Reheater	°F		129.3	×	115.0	300.0	calc	
1	Entrained Water Past Demister	% evap H2O		0.7900		None	None	0.7900	
1	Oxidation of CaSO3 to CaSO4	%		90.00	V	0.0	100.0	calc	
1	Wet FGD Power Requirement	% MWg		1.699	V	0.0	10.00	calc	
Pro	cess Type: Wet EGD	-							

Wet FGD – Performance input screen.

- **Maximum SO₂ Removal Efficiency:** This parameters specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual SO₂ removal efficiency for compliance.
- **Scrubber SO₂ Removal Efficiency:** This is the annual average  $SO_2$  removal efficiency achieved in the absorber. The calculated value assumes compliance with the SO₂ emission limit specified earlier, if possible. The efficiency is used to determine the liquid to gas ratio and emissions. This input is highlighted in blue.
- **Scrubber SO₃ Removal Efficiency:** The default value is taken from the removal efficiency reported in the literature (references are below). This efficiency then determines the mass of SO₃ removed from the flue gas in the collector. For more information see also:
  - www.netl.doe.gov/publications/proceedings/98/98fg/hardman.pdf
  - www.netl.doe.gov/publications/proceedings/98/98fg/rubin.pdf
- **Particulate Removal Efficiency:** This is the percent removal of particulate matter entering the FGD system from the upstream particulate collector. Particulate collectors are designed to comply with the specified particulate emission limit. This is additional particulate removal.
- **Absorber Capacity:** This is the percent of the flue gas treated by each operating absorber. This value is used to determine the number of operating absorbers and the capital costs.
- **Number of Operating Absorbers:** This is the number of operating scrubber towers. The number is determined by the absorber capacity and is used to calculate the capital costs. The value must be an integer.
- **Number of Spare Absorbers:** This is the total number of spare absorber vessels. It is used primarily to calculate capital costs. The value must be an integer.
- **Liquid to Gas Ratio:** The design of spray towers for high efficiency is achieved by using high liquid-to-gas (L/G) ratios. The calculated value is a function of the reagent type, the removal efficiency, and stoichiometry. It determines the power requirement and capital cost.
- **Reagent Stoichiometry:** This is the moles of calcium per mole of sulfur removed from the absorber. The stoichiometry is calculated as a function of the reagent type. It is used to determine the liquid to gas ratio, reagent usage, reagent waste, and capital cost.
- **Reagent Purity:** This is the percent of the reagent that is lime (CaO) or limestone (CaCO₃). The calculated value is a function of the reagent type. This parameter determines the waste solids produced and the reagent needed to remove the necessary  $SO_2$ .
- **Reagent Moisture Content:** This is the moisture content of the reagent. The remaining reagent impurities are assumed to be inert substances such as silicon dioxide (sand). This parameter is used to determine the waste solids produced.
- **Total Pressure Drop across FGD:** This is the total pressure drop across the FGD vessel prior to the reheater. This is used in the calculations of the power requirements (or energy penalty) and thermodynamic properties of the flue gas.

- **Temperature Rise Across ID Fan:** An induced draft (ID) fan is assumed to be located upstream of the FGD system. The fan raises the temperature of the flue gas due to dissipation of electro-mechanical.
- **Gas Temperature Exiting Scrubber:** A thermodynamic equation is used to calculate this equilibrium flue gas temperature exiting the scrubber. The gas is assumed to be saturated with water at the exiting temperature and pressure. The value determines the water evaporated in the scrubber.
- **Gas Temperature Exiting Reheater:** This is the desired temperature of flue gas after the reheater. It is assumed to be equal to the stack gas exit temperature. If scrubber bypass is employed, reheat requirements are reduced or eliminated. It determines the reheat energy required.
- **Entrained Water Past Demister:** This is a liquid water entrained in the flue gas leaving the demister expressed as a percentage of the total water evaporated in the absorber.
- **Oxidation of CaSO₃ to CaSO₄:** This parameter determines the mixture of chemical species (calcium sulfite and calcium sulfate) in the solid waste stream. The default values depend on the selection of forced or natural oxidation.
- Wet FGD Power Requirement: This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required for pumps and booster fans.

### Wet FGD Additives Inputs

This screen is only available for the **Combustion (Boiler)** plant type. If a limestone reagent with additives is selected from the **Config** input screen, the screen below will be displayed.

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0			Co	nfigure	Plant	Ĩ	Se	t <u>P</u> ara	amete	rs	Ĩ		<u>G</u> et Re	sults	
		Ove <u>r</u> al Plant	1	F <u>u</u> el	Base Plan	t <u>M</u> ercu	ury Con	Ox atro1	<u>T</u> S Con	P xol	<u>S</u> O2 Control	C <u>O</u> Capti	2 By-H ure M ₁	Prod. S gmt S	štac <u>k</u>
9					Title		Unit	5	Unc	Value	Calc	Min	Max	Default	
X		1	l Ch	loride Rem	oval Efficien	icy	%			90.00	)	0.0	100.0	90.00	
٥		2	2		<u> </u>					4000		4000		4000	
i.		3	1 Di	basic Acid	Makeum	on	ppm lh/ton SC	77 17 rem	_	1000		1000	2000	1000	- 111
P		-	5	ousic ricia	nuncup		10/101100	2 1010	_	10.00		0.0	30.00	10.00	
		6	5												
		7	7												
		8	3												
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-		1	1												
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		1	3												
		1	4												
		1	5												- 111
		1	7												
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		Pr	ocess	Type:	Vet FGD			7					÷		
			Conf	ig /	<u>2</u> . Performa	nce	<u>3</u> . Additiv	es /	<u>4</u> . R	etrofit Co	ist /	<u>5</u> . Capital	Cost 🖌	<u>6</u> . O&M Co	ost

Wet FGD – Additives input screen (for limestone and lime reagents)

The parameters are described briefly below.

- **Chloride Removal Efficiency:** Chlorides in the flue gas inlet stream are removed by the lime/limestone slurry. This parameter determines the amount of chlorides removed.
- **Dibasic Acid Concentration:** Dibasic acid (DBA) is added to limestone to reduce the liquid to gas ratio, enhancing the removal of SO₂. This is the concentration of DBA in the limestone slurry.
- **Dibasic Acid Makeup:** DBA is not completely recovered in the reagent feedback loop. This parameter is used to determine the makeup flow rate of DBA.

### Wet FGD Retrofit Cost Inputs

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for capital costs of modifications to process areas to implement the  $SO_2$  control technology are entered on the **Retrofit Cost** input screen for the Wet FGD system.

The retrofit cost factor of each process is a multiplicative cost adjustment which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Each parameter is described briefly below.

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	<u>(</u>	<u>C</u> onfigure :	Plant	Ĩ	Set <u>P</u> ar	amete	ers	Ĩ		<u>G</u> et Res	sults	
ľ	Overall Plant	Fuel	Base Plant	Mercu	ny <u>N</u> Ox Control	<u>T</u> S Con	SP trol C	SO2 ontro1	C <u>O</u> 2 By-Prod. Capture Mgmt Sta			ac <u>k</u>
l			Title		Units	Unc	Value	Calc	Min	Max	Default	
I	1	Capital C	Cost Process A	rea								
I	2	Reagent Feed	d System		retro \$/new \$		1.000		0.0	10.00	1.000	
I	3	SO2 Removal	1 System		retro \$/new \$		1.000		0.0	10.00	1.000	
I	4	Flue Gas Sys	tem		retro \$/new \$		1.000		0.0	10.00	1.000	
I	5	Solids Handli	ing System		retro \$/new \$		1.000		0.0	10.00	1.000	
I	6	General Supp	oort Area		retro \$/new \$		1.000		0.0	10.00	1.000	
I	7	Miscellaneou	ıs Equipment		retro \$/new \$		1.000		0.0	10.00	1.000	
I	8											
I	9											
I	10											
I	11											
I	12							_				
I	13							_				
I	14											
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I	17							_				
	18 Proc	ess Type: 🛛	Wet FGD		Y							
I	<u>1</u> .C	onfig /	2. Performanc	e 🖌	3. Additives	4. R	etrofit Cost	5	. Capital Co	st /	<u>6</u> . O&M Co	st /

Wet FGD – Retrofit Cost input screen.

### **Capital Cost Process Area**

- **Reagent Feed System:** This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.
- **SO2 Removal System:** This area deals with the cost of equipment for SO₂ scrubbing, such as absorption tower, recirculation pumps, and other equipment.
- **Flue Gas System:** This area treats the cost of the duct work and fans required for flue gas distribution to SO₂ system, plus gas reheat equipment.
- **Solids Handling System:** This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.
- **General Support Area:** The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.
- **Miscellaneous Equipment:** Any miscellaneous equipment is treated in this process area.

# Wet FGD Capital Cost Inputs

This screen is only available for the **Combustion (Boiler)** plant type.

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		<u>C</u> onfigure I	Plant ]	Set <u>P</u> a	ramet	ers	Ĩ		<u>G</u> et Res	sults	
	Overall Plant	Fuel	Base Plant Mer	cury <u>N</u> Ox Control	Cor	SP itro1 C	SO2 ontrol	C <u>O</u> 2 Capture	By-Pr Mg	nt Si	tac <u>k</u>
			Title	Units	Unc	Value	Calc	Min	Max	Default	
	1	Construction	Time	years		2.000		0.2500	10.00	calc	
	2										
	3	General Facili	ties Capital	%PFC		10.00		0.0	50.00	10.00	
	4	Engineering &	ž Home Office Fees	%PFC		10.00		0.0	50.00	10.00	
	5	Project Conti	ngency Cost	%PFC		15.00		0.0	100.0	15.00	
	6	Process Cont	ingency Cost	%PFC		2.000		0.0	100.0	2.000	
	7	Royalty Fees		%PFC		0.5000		0.0	10.00	0.5000	
	8										
	9	Pre-Pr	oduction Costs								
	10	Months of Fi	xed O&M	months		1.000		0.0	12.00	1.000	
	11	Months of V	ariable O&M	months		1.000		0.0	12.00	1.000	
	12	Misc. Capital	Cost	%TPI		2.000		0.0	10.00	2.000	
	13										
	14	Inventory Ca	pital	%TPC		0.5040		0.0	10.00	calc	
	15										
	16										
	17										
	18	TCR Recover	y Factor	%		100.0		0.0	100.0	100.0	
	Proc	ess Type: 🛛	Vet FGD	7							
1	1.0	onfig /	2 Performance	3 Additives	/ 45	etrofit Cost		5 Capital Co	et /	6 0.&M.Co	st /

Wet FGD – Capital Cost input screen.

Each parameter is described briefly below

- **Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).
- **Bypass Duct Cost Adder**: The bypass capital costs are not specified with the other process areas. This parameter allows any direct capital costs incurred by the addition of bypass ducts to be added to the Flue Gas System process area (see retrofit cost screen for a list of the direct cost process areas).
- **General Facilities Capital (GFC):** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.
  - **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
  - **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
  - **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a wet FGD that has been paid off.

# Wet FGD O&M Cost Inputs

This screen is only available for the **Combustion (Boiler)** plant type.

CQ2 Capture Min 0.0	By-Pr Mgr Max	od. nt Stack
C <u>O</u> 2 Capture Min 0.0	Max	od. nt Stack
<b>Min</b> 0.0	Max	Default
0.0	100.0	Deraut
	120.0	60.00
0.0	30.00	calc
0.0	100.0	calc
0.0	25.00	calc
0.0	30.00	calc
0.0	200.0	calc
0.0	30.00	6.670
0.0	10.00	4.750
0.0	100.0	24.82
0.0	10.00	calc
0.0	100.0	40.00
0.0	100.0	30.00
	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0         100.0           0.0         25.00           0.0         30.00           0.0         200.0           0.0         30.00           0.0         10.00           0.0         10.00           0.0         100.0           0.0         100.0           0.0         100.0           0.0         100.0

Wet FGD – O&M Cost input screen

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below:

- **Bulk Reagent Storage Time:** This is the number of days of bulk storage of reagent. This factor is used to determine the inventory capital cost.
- Limestone Cost: This is the cost of Limestone for the Wet FGD system.
- Lime Cost: This is the cost of Lime for the Wet FGD or Lime Spray Dryer system.
- **Dibasic Acid Cost:** This is the cost of the Dibasic Acid for the Wet FGD or Lime Spray Dryer system.
- Stacking Cost: This is the stacking cost as used for the Wet FGD system.
- **Waste Disposal Cost:** This is the sludge disposal cost for the FGD system.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work ( 3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks 6 weeks PTO) = 4.75 equiv. Shifts/day).
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- **Maint. Cost Allocated to Labor:** Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

### Wet FGD Diagram

This screen is only available for the Combustion (Boiler) plant type. The **Diagram** result screen displays an icon for theWet FGD SO₂ control technology selected and values for major flows in and out of it.



Wet FGD – Diagram.

Each result is described briefly below.

#### Reagent

- **Dry Reagent:** The total mass flow rate of lime, limestone or limestone with dibasic acid injected into the scrubber. This is a function of the SO₂ removal efficiency, the reagent purity and the reagent stoichiometric (all performance input parameters).
- **Makeup Water:** Water needed to replace the evaporated water in the reagent sluice circulation stream.

#### Flue Gas Entering FGD

- **Temperature In:** Temperature of the flue gas entering the scrubber. This is determined by the flue gas outlet temperature of the module upstream of the scrubber (e.g., a particulate removal technology).
- **Flue Gas In:** Volumetric flow rate of flue gas entering the scrubber, based on the flue gas temperature entering the scrubber and atmospheric pressure.
- **Fly Ash In:** Total solids mass flow rate in the flue gas entering the scrubber. This is determined by the solids exiting from the module upstream of the scrubber (e.g., a particulate removal technology).
- **Mercury In:** Total mass of mercury entering the scrubber. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).
- **Temperature:** Temperature of the flue gas entering the scrubber after the forced draft fan. This is determined by the flue gas inlet temperature of the FGD and the temperature rise across ID fan input parameter.

#### Flue Gas Exiting FGD

- **Temperature:** Temperature of the flue gas immediately on exiting the scrubber, prior to any flue gas bypass remixing and prior to reheating.
- **Temperature Out:** Temperature of the flue gas exiting the scrubber. This is a function of flue gas bypass, saturation temperature, reheater and .the flue gas component concentrations.
- **Flue Gas Out:** Volumetric flow rate of the flue gas exiting the scrubber after the reheater, based on the flue gas temperature exiting the scrubber and atmospheric pressure.
- **Fly Ash Out:** Total solids mass flow rate in the flue gas exiting the scrubber after the reheater. This is a function of the ash removal and flue gas bypass input parameters.
- **Mercury Out:** Total mass of mercury exiting the scrubber after the reheater. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

#### **FGD Performance**

- **Ash Removal:** Actual particulate removal efficiency in the scrubber. This is set by the scrubber ash removal input parameter.
- **SO2 Removal:** Actual removal efficiency of  $SO_2$  in the scrubber. This is a function of the maximum removal efficiency (scrubber performance input parameter) and the emission constraint for  $SO_2$  (emission constraints input parameter). It is possible that the scrubber may over or under-comply with the emission constraint.
- **SO3 Removal:** Percent of  $SO_3$  in the flue gas removed from the scrubber. The  $SO_3$  is assumed to combine with  $H_2O$  and leave with the ash solids or sluice water as a sulfate (in the form of  $H_2SO_4$ ).
- **Mercury Removal:** Percent of the total mercury removed from the scrubber. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

### **Collected Solids**

**Wet FGD Solids:** Total solids mass flow rate of solids removed from the scrubber. This is a function of the solids content in the flue gas and the particulate removal efficiency of the scrubber. The solids are shown on a wet basis.

### Wet FGD Flue Gas Results

This screen is only available for the Combustion (Boiler) plant type. The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the Wet FGD SO₂ Control Technology. For each component, quantities are given in both moles and mass per hour.

	<u>(</u>	<u>]</u> on	figure	Plant	Ĭ	Se	t <u>P</u> aramete	rs	<u>(</u>	<u>G</u> et Results	
ĺ	Ove <u>r</u> all Plant	F	uel	<u>B</u> oiler	<u>A</u> ir Preheater	<u>N</u> Ox Control	Mercury	TSP Control Co	O2 CO2 ntro1 Captu	re By-Prod. Mgmt	្រទ
				Major Flue	Gas Compo	nents	Total Flue Gas In (Ib-moles/hr)	Total Flue Gas Out (lb-moles/hr)	Total Flue Gas In (ton/hr)	Total Flue Gas Out (ton/hr)	
I		1	Nitrog	en (N2)			1.302e+05	1.302e+05	1823	1823	
I		2	Oxyge	n (02)			9685	9509	155.0	152.1	
I		3	Water	Vapor (H2C	))		1.671e+04	3.287e+04	150.5	296.1	
I		4	Carbos	n Dioxide (C	02)		2.096e+04	2.135e+04	461.1	469.8	
I		5	Carbo	n Monoxide	(CO)		0.0	0.0	0.0	0.0	
I		6	Hydro	chloric Acid	I (HCI)		19.71	1.971	0.3594	3.594e-02	
I		7	Sulfur	Dioxide (SC	2)		400.8	8.016	12.84	0.2568	
I		8	Sulfuri	ic Acid (equ	ivalent SO3)		2.066	1.033	8.272e-02	4.136e-02	
I		9	Nitric (	Oxide (NO)			11.29	11.29	0.1694	0.1694	
I		10	Nitrog	en Dioxide (	NO2)		0.5942	0.5942	1.367e-02	1.367e-02	
I		11	Ammo	mia (NH3)			0.3088	0.3088	2.629e-03	2.629e-03	
I		12	Argon	ı (At)			0.0	0.0	0.0	0.0	
I		13	Total				1.780e+05	1.940e+05	2604	2742	
I		14									
I		15						]			

Wet FGD – Flue Gas result screen.

Each result is described briefly below

### **Major Flue Gas Component**

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

### Wet FGD Bypass Results

This screen is only available for the Combustion (Boiler) plant type. The **Flue Gas Bypass** result screen displays a table of quantities of flue gas components entering and bypassing the Wet FGD SO₂ Control Technology. For each component, quantities are given in both moles and mass per hour.

	Configure Plant	Set <u>P</u> ara	meters	Ĩ	<u>G</u> et R	esults
Overall Plant	Fuel Boiler Air Preheater C	NOx Mercu	ary <u>T</u> SP Control	SO2 Control	C <u>O</u> 2 B Capture	y-Prod. St Mgmt St
	Major Flue Gas Components	Flue Gas Bypass (lb-moles/hr)	Flue Gas Into Scrubber (Ib-moles/hr)	Flue Gas Out Scrubber (Ib-moles/hr)	Flue Gas Bypass (ton/hr)	Flue Gas Inte Scrubber (ton/hr)
1	Nitrogen (N2)	0.0	1.302e+05	1.302e+05	0.0	1823
2	Oxygen (O2)	0.0	9685	9509	0.0	155.0
3	Water Vapor (H2O)	0.0	1.671e+04	3.274e+04	0.0	150.5
4	Carbon Dioxide (CO2)	0.0	2.096e+04	2.135e+04	0.0	461.1
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	0.0	19.71	1.971	0.0	0.3594
7	Sulfur Dioxide (SO2)	0.0	400.8	8.016	0.0	12.84
8	Sulfuric Acid (equivalent SO3)	0.0	2.066	1.033	0.0	8.272e-02
9	Nitric Oxide (NO)	0.0	11.29	11.29	0.0	0.1694
10	Nitrogen Dioxide (NO2)	0.0	0.5942	0.5942	0.0	1.367e-02
11	Ammonia (NH3)	0.0	0.3088	0.3088	0.0	2.629e-03
12	Argon (At)	0.0	0.0	0.0	0.0	0.0
13	Total	0.0	1.780e+05	1.938e+05	0.0	2604
14						
15						

Wet FGD – Bypass result screen.

Each result is described briefly below

#### **Major Flue Gas Component**

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

### Wet FGD Capital Cost Results

This screen is only available for the **Combustion (Boiler)** plant type. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the  $SO_2$  control technology.

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		Over Plar	all Fue	el <u>B</u> oiler	<u>A</u> ir Preheater	<u>N</u> Ox Control	Mero	cury	<u>T</u> SP Control Con	02 C <u>O</u> 2 tro1 Capture	By-Prod. Mgmt	Stack
			Wet I	FGD Process A	rea Costs	Capital ( (M\$)	Cost I		Wet FG	D Plant Costs	Capi (	ital Cost M\$)
C.		1	Reagent Fe	ed System		8.163	3	1	Process Facilities (	apital	4	8.09
<b>P</b>		2	SO2 Remov	al System		20.72	2	2	General Facilities C	apital	4	.809
		3	Flue Gas Sy	rstem		8.553	3	3	Eng. & Home Offic	e Fees	4	.809
		4	Solids Hand	Solids Handling System		8.228	3	4	Project Contingend	cy Cost	7	.214
$\geq$		5	General Sup	port Area		0.622	3	5	Process Continger	icy Cost	0.	9618
21		6	Miscellaneo	ous Equipment		1.805	5	6	Interest Charges (A	AFUDC)	3	.393
?		7	Process Fac	ilities Capital		48.09	3	7	Royalty Fees		0.	2405
-		8						8	Preproduction (Sta	rtup) Cost	2	.439
		9						9	Inventory (Workin	g) Capital	0.	.3321
		10					_	10	Total Capital Requ	irement (TCR)	7	<mark>2.29</mark>
		11					_	11				
		12					_	12				
		13					_	13				
		14						14				
		15					_	15	Effective TCR		7	2.29
		Pro	cess Type:	Wet FGD		Ŧ			Costs are in Co	onstant 2005 dolla	ars.	
			<u>1</u> . Diagram	2. Flue	Gas /	<u>3</u> . Bypass		4	Capital Cost	<u>5</u> . O&M Cost	<u>6</u> . Tota	1Cost /

Wet FGD – Capital Cost result screen.

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

#### **Direct Capital Costs**

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the scrubbers are the flue gas flow rate through the scrubber, the composition of the flue gas, the reagent stoichiometry, and the reagent flow rate.

- **Reagent Feed System:** This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.
- **SO₂ Removal System:** This area deals with the cost of equipment for SO₂ scrubbing, such as absorption tower, recirculation pumps, and other equipment.

- **Flue Gas System:** This area treats the cost of the duct work and fans required for flue gas distribution to SO₂ system, plus gas reheat equipment.
- **Solids Handling System:** This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.
- **General Support Area:** The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.
- **Miscellaneous Equipment:** Any miscellaneous equipment is treated in this process area.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

#### **Total Capital Costs**

Process Facilities Capital: (see definition above)

- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the wet FGD that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the wet FGD.

# Wet FGD O&M Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the  $SO_2$  control technology.

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*			Variable Cost Component	O&M Cost (M\$/yr)		Fixed Cost Component	O&M Cost (M\$/yr)
C.		1	Reagent	1.536	1	Operating Labor	2.009
s l		2			2	Maintenance Labor	1.154
		3	Steam	0.1023	3	Maintenance Material	1.731
-		4	Solid Waste Disposal	1.380	4	Admin. & Support Labor	0.9491
2		5	Electricity	3.763	5	Total Fixed Costs	5.844
<b>?</b> ∥		6	Water	1.604e-02	6		
?		7	Total Variable Costs	6.798	7		
-1		8			8		
		9			9		
		10			10		
		11			11		
		12			12		
		13			14		
		15			15	Total O&M Costs	12.64
		Pro	cess Type: Wet FGD	<b>_</b>		Costs are in Constant 2005 dollars.	
			<u>1</u> . Diagram 🖌 <u>2</u> . Flue Gas 🖌	<u>3</u> . Bypass	4	Capital Cost 🔬 <u>5</u> . O&M Cost 🔏	<u>6</u> . Total Cost /

Wet FGD – O&M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

#### **Variable Cost Components**

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

- **Reagent:** The total mass flow rate of lime or limestone injected into the scrubber on a wet basis. This is a function of the  $SO_2$  concentration in the flue gas and the reagent stoichiometric performance input value.
- **Steam:** Annual cost of steam used for direct or reheat use in the scrubber. This is a function of the steam heat rate, reheat energy requirement and gross plant capacity.
- **Solid Waste Disposal:** Total cost to dispose the collected flue gas waste solids. This does not consider by-product gypsum sold in commerce.
- **Electricity:** Cost of power consumption of the scrubber. This is a function of the gross plant capacity and the scrubber energy penalty performance input parameter.
- **Water:** Cost of water for reagent sluice in the scrubber. This is a function of the liquid to gas ratio performance input parameter for the wet FGD. The cost is a function of the flue gas flow rate and the slurry recycle ratio performance input parameter for the spray dryer.
- **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

#### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

# Wet FGD Total Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the  $SO_2$  control technology. The result categories are the same for both the Wet FGD and the Lime Spray Dryer.

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<i>≱</i> ∦ ₽			Cost	Component		M\$/yr	\$/MWh	\$/ton SO2 removed	Percent Total	
L		1 Annua	l Fixed Cost	t.		5.844	2.680	131.8	25.04	
		2 Annua 3 Total A	anable C Annual O&I	ul Cost		12.64	5.796	285.1	29.13 54.16	
	-	4 Annua 5 Total I	lized Capita .evelized Ar	1Cost mualCost		10.70 23.34	4.905	241.3 526.4	45.84 100.0	
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	Process T ₂	15 ype: We	et FGD		Y		Costs are in C	onstant 2005 d	ollars.	
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Wet FGD – Total Cost result screen.

### **Cost Component**

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

- **Annual Fixed Cost**: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# **Spray Dryer**

The **SO2 Control** Technology Navigation Tab contains screens that address postcombustion air pollution technologies for Sulfur Dioxide. The model includes options for a Lime Spray Dryer. A spray dryer is sometimes used instead of a wet scrubber because it provides simpler waste disposal and can be installed with lower capital costs. These screens are available if the **Lime Spray Dryer** SO₂ control technology has been selected in **Configure Plant** for the **Combustion (Boiler)** plant type.

# **Spray Dryer Configuration**

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for configuration of the **Lime Spray Dryer**  $SO_2$  control technology are entered on the **Config** input screen

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Spray Dryer – Config. input screen.

Each parameter is described briefly below.

Reagent: For the Lime Spray Dryer the only option is Lime.

• **Lime:** Magnesium Enhanced Lime System—A magnesium sulfite and lime slurry (maglime) is used to remove SO2 and form a precipitate high in calcium sulfite. The high alkalinity of the maglime slurry allows very high SO2 removal. However, the reagent cost is also higher and solid waste is not easily disposed.

# **Spray Dryer Performance Inputs**

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for performance of the **Lime Spray Dryer**  $SO_2$  control technology are entered on the **Performance** input screen.

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				Title		Units	Unc	Value	Calc	Min	Max	Default	
I		1	Actual SO2 R	emoval Efficier	ncy	%		80.70		0.0	100.0	calc	
I		2	Maximum SO2	2 Removal Effic	iency	%		90.00		70.00	100.0	90.00	
I		3	Actual SO3 R	emoval Efficier	ıcy	%		90.00		0.0	100.0	90.00	
I		4	Particulate Re	moval Efficien	cy	%		0.0		0.0	100.0	0.0	
II		5	Absorber Cap	acity		% acfm		50.00		0.0	200.0	50.00	
II		6	Number of Op	erating Absor	bers	number		2	V	Menu	Menu	calc	
II		7	Number of Sp	are Absorbers		number		1 🔹		Menu	Menu	1	
		8	Reagent Stoic	hiometry		mol Ca/mol S in		0.9867	M	0.5000	4.000	calc	
		9	CaO Content	ofLime		wt%		94.00		90.00	98.00	94.00	
		10	H2O Content	of Lime		wt %		0.7500		0.0	2.000	0.7500	
		11	Total Pressure	e Drop Across	FGD	in H2O gauge		6.000		0.0	20.00	6.000	
II		12	Approach to \$	Saturation Tem	nperat	deg. F		25.00		20.00	50.00	25.00	
II		13	Temperature H	Rise Across ID	Fan	deg. F		12.00		0.0	25.00	12.00	
1		14	Gas Temperat	ure Exiting Scr	ubber	deg. F		175.0		None	None	175.0	
I		15	Oxidation of C	CaSO3 to CaSO	4	%		35.00		10.00	50.00	35.00	
I		16	Slurry Recycle	e Ratio		lb slurry/lb lime		1.687	V	0.0	5.000	calc	
I		17											
		18	Spray Dryer P	ower Requiren	nent	% MWg		0.6707	Ľ	0.0	10.00	calc	
		Proc	ess Type: S	pray Dryer									
		<u>1</u> . C	onfig	2. Performanc	e 🧸	3. Retrofit Cost 🖌	<u>4</u> . (	Capital Cost	1	5. O&M Co	st /		

Spray Dryer – Performance input screen.

In a Lime Spray Dryer, an atomized spray of a mixture of lime slurry and recycled solids is brought into contact with the hot flue gas. The water in the slurry evaporates leaving dry reaction products and flyash, which drops out of the scrubber. A particulate control device such as a baghouse is also used to remove the rest of the dry products from the flue gas before releasing it. The SO₂ removal efficiency is the total of SO₂ removed in the scrubber and the baghouse.

Many lime spray dryer input parameters are similar to those defined above for wet lime/limestone systems. Each parameter is described briefly below.

- Actual SO₂ Removal Efficiency: This is the annual average  $SO_2$  removal efficiency achieved in the absorber. The calculated default value assumes compliance with the  $SO_2$  emission limit specified earlier, if possible. The default value reflects other model parameter values, including the sulfur retained in bottom ash. This input is highlighted in blue.
- **Maximum SO₂ Removal Efficiency:** This parameters specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual SO₂ removal efficiency for compliance.

- **Actual SO₃ Removal Efficiency:** The default value is taken from the removal efficiency reported in the literature (references are below). This efficiency then determines the mass of SO₃ removed from the flue gas in the collector. For more information see also:
  - www.netl.doe.gov/publications/proceedings/98/98fg/hardman.pdf
  - www.netl.doe.gov/publications/proceedings/98/98fg/rubin.pdf
- **Particulate Removal Efficiency:** Ash and particulate matter are assumed to be removed by a separate particulate removal device, such as a fabric filter. However, this parameters is provided for conditions where particulates are removed directly from the scrubber.
- **Absorber Capacity:** This is the percent of the flue gas treated by each operating absorber. This value is used to determine the number of operating absorbers and the capital costs.
- **Number of Operating Absorbers:** This is the number of operating scrubber towers. The number is determined by the absorber capacity and is used to calculate the capital costs. The value must be an integer.
- **Number of Spare Absorbers:** This is the total number of spare absorber vessels. It is used primarily to calculate capital costs. The value must be an integer.
- **Reagent Stoichiometry:** This is the moles of calcium per mole of sulfur into the absorber. The stoichiometry is calculated as a function of the required  $SO_2$  removal efficiency, inlet flue gas temperature, inlet sulfur concentration, and approach to saturation temperature.
- **CaO Content of Lime:** This is the percent of reagent that is pure lime (CaO). This parameter determines the waste solids produced and the reagent mass requirements, given the stoichiometry needed for  $SO_2$  removal.
- **H2O Content of Lime:** This is the moisture content of the lime (CaO). The remaining reagent impurities are assumed to be inert substances such as silicon dioxide (sand). This parameter is used to determine the waste solids produced.
- **Total Pressure Drop Across FGD:** This is the total pressure drop across the spray dryer vessel prior to the reheater. This is used in the calculations of the power requirements (or energy penalty) and thermodynamic properties of the flue gas.
- **Approach to Saturation Temperature:** This defines the gas temperature exiting the absorber. The approach is the increment over the water saturation temperature at the exit pressure. As the approach to saturation temperature increases, the evaporation time decreases thereby decreasing removal efficiency.
- **Temperature Rise Across ID Fan:** An induced draft (ID) fan is assumed to be located upstream of the FGD system. The fan raises the temperature of the flue gas due to dissipation of electro-mechanical energy.
- **Gas Temperature Exiting Scrubber:** A thermodynamic equation is used to calculate this equilibrium flue gas temperature exiting the scrubber. The gas is assumed to be saturated with water at the exiting temperature and pressure. The value determines the water evaporated in the scrubber.

- **Oxidation of CaSO3 to CaSO4:** This parameter determines the mixture of the two chemical species in the solid waste stream.
- **Slurry Recycle Ratio:** An atomized spray of a mixture of lime slurry and recycled solids is brought into contact with the hot flue gas. This parameter specifies the amount of solid waste recycled and lime slurry used. It is calculated from the sulfur content of the coal.
- **Spray Dryer Power Requirement:** This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required for pumps and booster fans.

# **Spray Dryer Retrofit Cost**

This screen is only available for the Combustion (Boiler) plant type. Inputs for capital costs of modifications to process areas to implement the  $SO_2$  control technology are entered on the **Retrofit Cost** input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

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	1	Capital C	Cost Process Area									
	2	Reagent Feed	1 System	1	etro \$/new \$		1.000		0.0	10.00	1.000	
	3	SO2 Removal	lSystem	1	retro \$/new \$		1.000		0.0	10.00	1.000	
	4	Flue Gas Sys	tem	1	retro \$/new \$		1.000		0.0	10.00	1.000	
	5	Solids Handli	ing System	1	retro \$/new \$		1.000		0.0	10.00	1.000	
	6	General Supp	ort Area	1	etro \$/new \$		1.000		0.0	10.00	1.000	
	7	Miscellaneou	ıs Equipment	1	retro \$/new \$		1.000		0.0	10.00	1.000	
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Spray Dryer – Retrofit Cost input screen.

Each parameter is described briefly below.

- **Reagent Feed System:** This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.
- **SO₂ Removal System:** This area deals with the cost of equipment for SO₂ scrubbing, such as absorption tower, recirculation pumps, and other equipment.
- **Flue Gas System:** This area treats the cost of the duct work and fans required for flue gas distribution to SO₂ system, plus gas reheat equipment.
- **Solids Handling System:** This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.
- **General Support Area:** The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.
- **Miscellaneous Equipment:** Any miscellaneous equipment is treated in this process area.

# **Spray Dryer Capital Cost Inputs**

This screen is only available for the Combustion (Boiler) plant type.

	maaea	a (° )		Y	<i>(</i> ) <b>D</b>			-			1.	
		Configure 1	Plant		Set Par	amete	rs		-	Get Res	uuts	
(	Ove <u>r</u> all Plant	Fuel	Base Plant	<u>M</u> ercury	<u>N</u> Ox Control	Con	SP tro1 Co	O2 ntrol	C <u>O</u> 2 Capture	By-Pr Mgi	nt St	ac <u>k</u>
Γ			Title		Units	Unc	Value	Calc	Min	Max	Default	
	1	Construction	Time		years		3.000		0.2500	10.00	3.000	
	2											
	3	General Facili	ties Capital		%PFC		10.00		0.0	50.00	10.00	
	4	Engineering &	k Home Office Fe	es	%PFC		10.00		0.0	50.00	10.00	
	5	Project Conti	ngency Cost		%PFC		15.00		0.0	100.0	15.00	
	6	Process Cont	ingency Cost		%PFC		4.000		0.0	100.0	4.000	
	7	Royalty Fees			%PFC		0.5000		0.0	10.00	0.5000	
	8											
	9	Pre-Pr	oduction Costs									
	10	Months of Fi	xed O&M		months		1.000		0.0	12.00	1.000	
	11	Months of Va	ariable O&M		months		1.000		0.0	12.00	1.000	
	12	Misc. Capital	Cost		%TPI		2.000		0.0	10.00	2.000	
	13											
	14	Inventory Ca	pital		%TPC		1.672		0.0	10.00	calc	
	15											
	16											
	17											
	18	TCR Recover	y Factor		%		100.0		0.0	100.0	100.0	
	Proc	ess Type:	nrav Drvor		-							

Spray Dryer – Capital Cost input screen.

Inputs for capital costs are entered on the Capital Cost input screen.

- **Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).
- **General Facilities Capital (GFC)**: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable

O&M costs are described below with the addition of a miscellaneous capital cost factor.

- Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

# Spray O&M Cost Inputs

ECN Ec	dit <u>V</u> iew 0	io <u>W</u> indow <u>H</u> elp							
		Configure Plant	Set <u>P</u> ara	amete	rs	Ţ		<u>G</u> et Res	sults
	Overali Plant	Fuel Base Plant Mercu	ury <u>N</u> Ox Control	<u>T</u> S Con	P S trol Co	O2 ntrol	C <u>O</u> 2 Capture	By-Pr Mgi	od. mt Stac <u>k</u>
		Title	Units	Unc	Value	Calc	Min	Max	Default
	1	Bulk Reagent Storage Time	days		60.00		0.0	120.0	60.00
	2		<b>*</b> 0		70.04		10.00		
	3	Lime Cost Weste Discoss! Cost	\$/ton		10.50		40.00	90.00	caic
	4	Flectricity Price (Base Plant)	\$75.000	_	41.12		0.0	None	calc
	6	Licentery Thee (Duse Thure)			41.12		0.0	None	
	7	Number of Operating Jobs	jobs/shift		5.330		0.0	30.00	5.330
	8	Number of Operating Shifts	shifts/day		4.750		0.0	10.00	4.750
	9	Operating Labor Rate	\$/hr		24.82		0.0	100.0	24.82
	10								
	11	Total Maintenance Cost	%TPC		4.227		0.0	10.00	calc
	12	Maint. Cost Allocated to Labor	% total		40.00		0.0	100.0	40.00
	13	Administrative & Support Cost	% total labor		30.00		0.0	100.0	30.00
	14								
	15								
	17								
	18								
	Proc	ess Type: Spray Dryer	·		Costs are	in Con	stant 2005	dollars.	
	<u>1</u> .C	onfig <u>2</u> . Performance	<u>3</u> . Retrofit Cost /	<u>4</u> . C	apital Cost		<u>5</u> . O&M Cos	;t	

This screen is only available for the **Combustion (Boiler)** plant type.

Spray Dryer – O&M Cost input screen.

Inputs for operation and maintenance are entered on the **O&M Cost** input tab. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below

- **Bulk Reagent Storage Time:** This is the number of days of bulk storage of reagent. This factor is used to determine the inventory capital cost.
- Lime Cost: This is the cost of Lime for the Wet FGD or Lime Spray Dryer system.
- **Waste Disposal Cost:** This is the sludge disposal cost for the FGD system.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is for the **Combustion (Boiler) Model** is a combustion boiler and an air preheater.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

# **Spray Dryer Diagram**

This screen is only available for the **Combustion (Boiler)** plant type.



Spray Dryer – Diagram

The **Diagram** result screen displays an icon for the Lime Spray Dryer SO₂ control technology selected and values for major flows in and out of it. Each result is described briefly below:

#### Reagent

**Dry Reagent:** The total mass flow rate of lime, limestone or limestone with dibasic acid injected into the scrubber. This is a function of the SO₂ removal efficiency, the reagent purity and the reagent stoichiometric (all performance input parameters). The reagent is assumed to be dry.

#### Flue Gas Entering Dryer

- **Temperature In:** Temperature of the flue gas entering the scrubber. This is determined by the flue gas outlet temperature of the module upstream of the scrubber (e.g., a particulate removal technology).
- **Flue Gas In:** Volumetric flow rate of flue gas entering the scrubber, based on the flue gas temperature entering the scrubber and atmospheric pressure.
- **Fly Ash In:** Total solids mass flow rate in the flue gas entering the scrubber. This is determined by the solids exiting from the module upstream of the scrubber (e.g., a particulate removal technology).
- **Mercury In:** Total mass of mercury entering the scrubber. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

### Flue Gas Exiting Dryer

- **Temperature:** Temperature of the flue gas immediately after exiting the scrubber. This is a function of saturation temperature, and .the flue gas component concentrations. This temperature is used to determine the flue gas bypass required.
- **Temperature:** Temperature of the flue gas immediately after exiting the induced draft fan. This is a function of flue gas temperature exiting the scrubber, the flue gas bypass and the temperature rise across ID fan input parameter.
- **Temperature Out:** Temperature of the flue gas immediately after exiting the reheater. This is determined by the gas temperature exiting reheater input parameter.
- **Flue Gas Out:** Volumetric flow rate of the flue gas exiting the reheater, based on the flue gas temperature exiting the scrubber and atmospheric pressure.
- **Solids Out:** Total solids mass flow rate in the flue gas exiting the reheater. This is a function of the ash removal parameter on the scrubber performance input screen.
- **Mercury Out:** Total mass of mercury exiting the scrubber after the reheater. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

#### **Spray Dryer Performance**

- **Ash Removal:** Actual particulate removal efficiency in the scrubber. This is set by the scrubber performance input parameter.
- **SO₂ Removal:** Actual removal efficiency of SO₂ in the scrubber. This is a function of the maximum removal efficiency (scrubber performance input parameter) and the emission constraint for SO₂ (emission constraints input parameter). It is possible that the scrubber may over or under-comply with the emission constraint.
- $SO_3$  Removal: Percent of SO₃ in the flue gas removed from the scrubber. The SO₃ is assumed to combine with H₂O and leave with the ash solids or sluice water as a sulfate (in the form of H₂SO₄).
- **Mercury Removal:** Percent of the total mercury removed from the scrubber. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

### **Collected Solids**

**Dry Solids:** Total solids mass flow rate of solids removed from the scrubber. This is a function of the solids content in the flue gas and the particulate removal efficiency of the scrubber. The solids are assumed to be dry.

# **Spray Dryer Flue Gas Results**

	🗧 Untitled*							
	<u>(</u>	<u>C</u> on	figure Plant 🔰 Set	t <u>P</u> arameter	s T	<u>(</u>	Get Results	
	Overall P <u>l</u> ant	F	<u>u</u> el <u>B</u> oiler <u>A</u> ir <u>N</u> Ox Preheater Control	Mercury	<u>T</u> SP Control Cor	D2 C <u>O</u> 2 utrol Captu	re <u>M</u> gmt	Stac <u>k</u>
			Major Flue Gas Components	Flue Gas In (b-moles/hr)	Flue Gas Out (lb-moles/hr)	Flue Gas In (ton/hr)	Flue Gas Out (ton/hr)	
		1	Nitrogen (N2)	1.266e+05	1.266e+05	1773	1773	
Ι		2	Oxygen (O2)	9409	9379	150.5	150.1	
Ι		3	Water Vapor (H2O)	1.406e+04	2.413e+04	126.7	217.4	
Ι		4	Carbon Dioxide (CO2)	2.050e+04	2.050e+04	451.0	451.0	
Ι		5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	
Ι		6	Hydrochloric Acid (HCl)	5.643	5.643	0.1029	0.1029	
Ι		7	Sulfur Dioxide (SO2)	213.0	41.12	6.823	1.317	
Ι		8	Sulfuric Acid (equivalent SO3)	1.468	0.1468	5.875e-02	5.875e-03	
Ι		9	Nitric Oxide (NO)	10.99	10.99	0.1649	0.1649	
Ι		10	Nitrogen Dioxide (NO2)	0.5783	0.5783	1.330e-02	1.330e-02	
Ι		11	Ammonia (NH3)	0.7392	0.7392	6.294e-03	6.294e-03	
Ι		12	Argon (Ar)	0.0	0.0	0.0	0.0	
Ι		13	Total	1.708e+05	1.807e+05	2508	2593	
Ι		14						
Ι		15						
	Process	Туре	Spray Dryer					

This screen is only available for the **Combustion (Boiler)** plant type.

Spray Dryer – Flue Gas result screen.

#### **Major Flue Gas Components**

Each result is described briefly below:

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCI): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **Spray Dryer Capital Cost Results**

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6			<u>C</u> onfigure Plant	Set <u>P</u> ar	ame	ters <u>G</u> et Re	sults
		Ove; Plai	all it Fuel <u>B</u> oiler <u>A</u> ir Preheater	NOx Control Merc	cury	TSP SO2 CQ2 By   Control Control Capture M	-Prod. Igmt Stac <u>k</u>
<i>∰</i> ∦ ₽∎			Spray Dryer Process Area Costs	Capital Cost (M\$)		Spray Dryer Plant Costs	Capital Cost (M\$)
C.	Ш	1	Reagent Feed System	5.661	1	Process Facilities Capital	28.55
1 1	Ш	2	SO2 Removal System	12.97	2	General Facilities Capital	2.855
	Ш	3	Flue Gas System	7.041	3	Eng. & Home Office Fees	2.855
	Ш	4	Solids Handling System	0.7263	4	Project Contingency Cost	4.282
	Ш	5	General Support Area	0.6778	5	Process Contingency Cost	1.142
<u> ?</u> ]	Ш	6	Miscellaneous Equipment	1.471	6	Interest Charges (AFUDC)	4.227
2	Ш	7	Process Facilities Capital	28.55	7	Royalty Fees	0.1427
<u>.                                    </u>	Ш	8			8	Preproduction (Startup) Cost	0.8782
	Ш	9			9	Inventory (Working) Capital	0.6633
	Ш	10			10	Total Capital Requirement (TCR)	45.59
		11			11		
	Ш	12			12		
	Ш	13			13		
	Ш	14			14		
	11	15			15	Effective TCR	45.59
		Pro	cess Type: Spray Dryer	Y		Costs are in Constant 2005 dollars.	
			1. Diagram 🖌 2. Flue Gas 🔪 3	.CapitalCost	4	. O&M Cost / <u>5</u> . Total Cost /	

This screen is only available for the **Combustion (Boiler)** plant type.

Spray Dryer – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the direct and indirect capital costs. Capital costs are typically expressed in either constant or current dollars for a

specified year, as shown on the bottom of the screen. Each result is described briefly below:

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the scrubbers are the flue gas flow rate through the scrubber, the composition of the flue gas, the reagent stoichiometry, and the reagent flow rate.

- **Reagent Feed System:** This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.
- **SO₂ Removal System:** This area deals with the cost of equipment for SO₂ scrubbing, such as absorption tower, recirculation pumps, and other equipment.
- **Flue Gas System:** This area treats the cost of the duct work and fans required for flue gas distribution to SO₂ system, plus gas reheat equipment.
- **Solids Handling System:** This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.
- **General Support Area:** The cost associated with the equipment required to support spray dryer system operation such as makeup water and instrument air are treated here.
- **Miscellaneous Equipment:** Any miscellaneous equipment is treated in this process area.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.
- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

# Spray Dryer O&M Results

This screen is only available for the **Combustion (Boiler)** plant type.

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ы	5-	Unti	tled*				
	Γ		<u>C</u> onfigure Plant	Set <u>P</u> ar	ame	ters Get R	esults
		Ove; Pla	rall Fuel Boiler Air nt Fuel Boiler Preheater	NOx Control Mer	cury	TSP SO2 CO2 B Control Control Capture	y-Prod. Stac <u>k</u> Mgmt Stac <u>k</u>
*			Variable Cost Component	O&M Cost (M\$/yr)		Fixed Cost Component	O&M Cost (M\$/yr)
C.	Ш	1	Reagent	2.482	1	Operating Labor	1.606
P	Ш	2	Steam	0.6308	2	Maintenance Labor	0.6710
	Ш	3	Solid Waste Disposal	0.9538	3	Maintenance Material	1.006
	Ш	4	Electricity	0.9081	4	Admin. & Support Labor	0.6830
	Ш	5	Water	1.339e-02	5	Total Fixed Costs	3.966
8	Ш	6	Total Variable Costs	4.988	6		
N?	Ш	7			7		
	Ш	8			8		
	Ш	9			9		
	Ш	10			10		
	Ш	11			11		
	Ш	12			12		
	Ш	13			13		
	Ш	14			14	T - LOOM G	0.054
		Pro	cess Type: Spray Dryer	V	15	Costs are in Constant 2005 dollars.	0.304
		\	1. Diagram / 2. Flue Gas / 3	3. Capital Cost	<u>\</u>	. O&M Cost 5. Total Cost /	

Spray Dryer – O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the  $SO_2$  control technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

#### **Variable Cost Components**

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

- **Reagent:** Annual cost of lime or limestone injected into the scrubber on a wet basis. This is a function of the  $SO_2$  concentration in the flue gas and the reagent stoichiometric performance input value.
- **Steam:** Annual cost of steam used for direct or reheat use in the scrubber. This is a function of the steam heat rate, reheat energy requirement, and gross plant capacity.
- **Solid Waste Disposal:** Total cost to dispose the collected flue gas waste solids. This does not consider by-product gypsum sold in commerce.
- **Power:** Cost of power consumption of the scrubber. This is a function of the gross plant capacity and the scrubber energy penalty performance input parameter.
- **Water:** Cost of water for reagent sluice in the scrubber. This is a function of the liquid to gas ratio performance input parameter for the wet FGD. The cost is a function of the flue gas flow rate and the slurry recycle ratio performance input parameter for the spray dryer.
- **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

#### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

# **Spray Dryer Total Cost Results**

This screen is only available for the Combustion (Boiler) plant type.

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5	<u>(</u>	Configure Plant	Set	t <u>P</u> arameter	rs Ì	<u>(</u>	Get Results	Ĩ
	Overall Plant	Fuel <u>B</u> oiler <u>A</u> ir Preheater	<u>N</u> Ox Control	Mercury	TSP Control	02 ntrol CO2 Captu	re By-Prod. Mgmt	Stac <u>k</u>
		Cost Component		M\$/yr	\$/MWh	\$/ion SO2 removed	Percent Total	
		Annual Fixed Cost Annual Variable Cost		3.966 4.988	1.762	107.6	25.26	
		3 Total Annual O&M Cost		8.954	3.977	242.9	57.03	
		Annualized Capital Cost Total Levelized Annual Cost		6.747 15.70	2.997 6.975	183.1 426.0	42.97 100.0	
		6 7						
		8						
		10						
		12						
		13 14 15						
	Process	Type: Spray Dryer	7		Costs are in C	onstant 2005 d	ollars.	
	<u>1</u> . Di	agram 🖌 2. Flue Gas 🖌	<u>3</u> . Capital Co	ost <u>(</u> <u>4</u> .0	&M Cost 🗼	<u>5</u> . Total Cost		

Spray Dryer – Total Cost result screen.

## **Cost Component**

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# **Amine System**

The amine  $CO_2$  scrubber is a post-combustion capture technology. It is only used in the **Combustion (Boiler)** and **Combustion (Turbine)** plant type configurations.

# Amine System Configuration

This screen is only available for the Combustion (Boiler) and Combustion (Turbine) plant types. The screens under the  $CO_2$  Capture Technology Navigation Tab display and design flows and data related to the Amine System.

	Configure Plant	Set <u>P</u> ar	amet	ers		9	Get Re	sults
Ove <u>r</u> all Plant	F <u>u</u> el <u>B</u> ase Plant <u>M</u> er	cury <u>N</u> Ox Control	Ti Cor	SP <u>S</u> ntrol Cor	D2 ntro1	C <u>O</u> 2 Capture	By-P: Mg	rod. mt Stac <u>k</u>
	Title	Units	Unc	Value	Calc	Min	Max	Default
1	Sorbent Used			MEA 🔻		Menu	Menu	MEA
2	Direct Contact Cooler (DCC) Used?	?		Yes 🔻		Menu	Menu	Yes
3	Temperature Exiting DCC	°F		122.0	V	110.0	250.0	calc
4	Auxiliary Natural Gas Boiler?			None 🔻		Menu	Menu	None
5								
6	Flue Gas Bypass Control			Bypass 🔻		Menu	Menu	No Bypass
7	Maximum CO2 Removal Efficiency	%		90.00		0.0	100.0	90.00
8	Overall CO2 Removal Efficiency	%		90.00	V	0.0	100.0	calc
9	(Required by CO2 emis. constraint	9						
10	Absorber CO2 Removal Efficiency	%		90.00	V	60.00	99.00	calc
11	Minimum Bypass	%		0.0		0.0	100.0	0.0
12	Allowable Bypass	%		0.0	V	0.0	100.0	calc
13	Actual Bypass	%		0.0	V	0.0	100.0	calc
14	•							
14	Reference Plant							
10	(Inputs for Avoidance Cost Calc.)							
13	CO2 Emission Rate	lbs/kWh		0.0	V	0.0	5.000	calc
18	Cost of Electricity	\$/MWh		0.0	V	0.0	150.0	calc

Amine System – Config. input screen (flue gas bypass added).

The parameters below describe the amine system alone. Additional parameters may be added to the screen if an auxiliary boiler or flue gas bypass is specified in the menus provided. The common input parameters are:

- **Sorbent Used:** MEA is the sorbent used in the system and the nominal values of various parameters are based on a process simulation model that uses MEA. At present, no other sorbents are included.
- **Direct Contact Cooler (DCC) Used:** A DCC is configured by default to cool the flue gas before it enters the amine system. The lower flue

gas temperature enhances the absorption reaction (absorption of  $CO_2$  in MEA sorbent is an exothermic process) and decreases the flue gas volume. The typically acceptable range of flue gas temperature is about 120-140 °F. A DCC is often not needed if a wet FGD is installed upstream.

- **Temperature Exiting DCC:** This is the temperature exiting the DCC. The desirable temperature of the flue gas entering the CO₂ capture system is about 113-122 °F. If the inlet temperature to the DCC is at or below this temperature, the DCC is not used. *This variable is only displayed if a DCC is specified.*
- Auxiliary Natural Gas Boiler?: An auxiliary natural gas-fired boiler can be added to the amine system. The options available are **None**, **Steam Only**, and **Steam + Power**. It may be added to generate separate power for the amine system (mainly compressors) and low pressure steam for sorbent regeneration. When used, the original steam cycle of the power plant remains undisturbed and the net power generation capacity of the power plant is not adversely affected. The auxiliary boiler comes at an additional cost of capital requirement for the boiler (and turbine) and the cost of supplemental fuel. Also, the auxiliary boiler adds to the  $CO_2$  and  $NO_x$  emissions. When an auxiliary boiler is added, an additional process type will be added to the selection menu at the bottom of the screen.
- Flue Gas Bypass Control: This popup selection menu controls whether or not a portion of the inlet flue gas may bypass the scrubber and recombine with the treated flue gas. Bypass allows the scrubber to operate at full efficiency while allowing some of the flue gas to go untreated. Two choices are available: **No Bypass** and **Bypass**. The no bypass option is the default and forces the entire flue gas to pass through the scrubber. The bypass option allows for the possibility of a portion of the flue gas to bypass the scrubber. The amount of bypass is controlled by several additional input parameters described below.
- **Maximum SO₂ Removal Efficiency:** This parameters specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual SO₂ removal efficiency for compliance. *This is only visible if bypass is specified*.
- **Overall SO₂ Removal Efficiency:** This value is the SO₂ removal efficiency required for the entire power plant to meet the SO₂ emission constraint set earlier. It is used to determine the actual flue gas bypass above. *This is only visible if bypass is specified*.
- **Scrubber SO₂ Removal Efficiency**: This is the actual removal efficiency of the scrubber alone. It is a function of the SO₂ emission constraint and the actual flue gas bypass. This value is also shown on the next input screen. *This is only visible if bypass is specified*.
- **Minimum Bypass:** This specifies the trigger point for allowing flue gas to bypass the scrubber. No bypass is allowed until the allowable amount reaches the minimum level set by this parameter. *This is only visible if bypass is specified.*
- **Allowable Bypass**: This is the amount of flue gas that is allowed to bypass the scrubber, based on the actual and maximum performance of the SO₂ removal. It is provided for reference only. The model determines the bypass that produces the maximum SO₂ removal and compares this potential bypass with the minimum bypass value

specified above. Bypass is only allowed when the potential bypass value exceeds the minimum bypass value. *This is only visible if bypass is specified*.

**Actual Bypass:** This displays the actual bypass being used in the model. It is based on all of the above and is provided for reference purposes only. *This is only visible if bypass is specified.* 

#### **Reference Plant**

The following reference plant inputs are used to determine the avoided cost of  $CO_2$  avoidance. The default value is zero for both parameters, requiring the user to supply the actual reference plant values. Reference values can be obtained by simulating the same plant configuration minus the  $CO_2$  capture. Analysts commonly express the cost of an environmental control system in terms of either the cost per ton of pollutant removed or the cost per ton "avoided." For an energy-intensive system like amine scrubbers there is a big difference between the cost per ton  $CO_2$  removed and the cost per ton  $CO_2$  avoided based on *net* plant capacity. Since the purpose of adding a capture unit is to reduce the  $CO_2$  emissions per net kWh delivered, the cost of  $CO_2$  avoidance (relative to a reference plant with no  $CO_2$  control) is the economic indicator most widely used. The reference plant parameters required are:

**CO₂ Emission Rate:** This is the emission rate for the reference power plant (without CO₂ capture)

# **Auxiliary Boiler Configuration**

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.

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Ø			Configure Plant	Set Par	amete	rs		1	<u>G</u> et Res	ults	
		Ove <u>r</u> all Plant	Fuel <u>B</u> ase Plant Mercu	ury <u>N</u> Ox Control	<u>T</u> S Con	SP <u>S</u> trol Co	02 ntrol	C <u>O</u> 2 Capture	By-Pr Mgr	od. nt Sta	c <u>k</u>
8			Title	Units	Unc	Value	Calc	Min	Max	Default	
X		1	Gas Boiler Efficiency	%		82.00		0.0	100.0	82.00	
8		2	Excess Air	%		8.000	M	0.0	100.0	calc	
		3	Nitrogen Oxide Emission Rate	1b NO2/MCF		275.0	V	0.0	1000	calc	
		4	Percent of NOx as NO	vol %		96.70		90.00	100.0	96.70	
B		5	Steam Turbine Efficiency	%		20.00		0.0	100.0	20.00	
8		6									
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		18									
		Pro	ess Type: Aux. Boiler System	•							
		<u>1</u> . Peri	formance								

Aux. Boiler System – Performance input screen

**Cost of Electricity:** This is the cost of electricity for the reference power plant (without CO₂ capture)

An auxiliary boiler may be added to the amine system to produced additional power and steam. It is accessed by using the "Process Type:" menu at the bottom of the input screen. Use this menu to return to the amine system input screens. If an auxiliary boiler is specified, the following parameters are available:

- **Gas Boiler Efficiency:** This is the percentage of fuel input energy transferred to steam in the boiler. The model default is based on standard algorithms described in the literature. It takes into consideration the energy losses due to inefficient heat transfer across the preheater, latent heat of evaporation, incomplete combustion, radiation losses, and unaccounted losses.
- **Excess Air:** This is the excess theoretical air used for combustion in the auxiliary boiler.
- Nitrogen Oxide Emission Rate: This parameter establishes the level of NOx emissions from the boiler. The default value reflects the AP-42 EPA emission factor, which is a function of boiler firing method and the coal rank. The value is given in pounds of equivalent NO2 per ton of coal.
- **Percent of NO_x as NO:** This parameter establishes the level of nitric oxide (NO) in the flue gas stream. The remainder of the total NOx emissions is assumed to be nitrogen dioxide (NO2). The default parameter reflects the AP-42 EPA emission factor, which is dependent on the fuel type.
- **Steam Turbine Efficiency:** The steam turbine efficiency may be considered the power generation efficiency when converting heat of the low pressure (LP) steam into usable electricity. The efficiency is much lower due to the low quality of the steam being converted. This is only visible when steam and power are specified.

# **Amine System Performance Inputs**

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.

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	Ove <u>r</u> all Plant	Fuel	<u>B</u> ase Plant	<u>M</u> ercu	uy <u>N</u> O Cont	x rol	<u>T</u> S Con	P irol	<u>S</u> C Con	)2 trol	C <u>O</u> 2 Capture	By-Pr Mgr	rod. mt S	itac <u>k</u>
			Title		Units		Unc	Value	•	Calc	Min	Max	Default	1
l	1	Maximum CO	2 Removal Effi	ciency	%			90.00	)		0.0	100.0	90.00	
I	2	Scrubber CO2	Removal Effic	iency	%	1		90.00	)	M	60.00	99.00	calc	
I	3	Oth	er Removals											
l	4	SO2 Removal	Efficiency		%			99.50	)	M	0.0	100.0	calc	
l	5	SO3 Removal	Efficiency		%			99.50		M	0.0	100.0	calc	
l	6	NO2 Remova	l Efficiency		%			25.00	)	M	0.0	100.0	calc	
l	7	HC1 Removal	Efficiency		%			95.00		M	0.0	100.0	calc	
l	8	Particulate Re	moval Efficien	cy	%			50.00		M	0.0	100.0	calc	
l	9													
l	10													
l	11													
l	12	Maximum Tra	in CO2 Capaci	у	ton/hr			230.0		V	0.0	300.0	calc	
l	13	Number of Op	perating Absor	bers	intege:	:		2		V	Menu	Menu	calc	
l	14	Number of Sp	are Absorbers		intege:	:		0	•		Menu	Menu	0	
l	15	Max CO2 Cor	npressor Capa	ity	ton/hr			330.0		V	0.0	500.0	calc	
l	16	No. of Operat	ing CO2 Comp	ressors	intege:	:		2		V	Menu	Menu	calc	
l	17	No. of Spare (	CO2 Compress	ors	intege	:		0	-		Menu	Menu	0	
I	18	Amine Scrub	ber Power Requ	irement	% MW	g		24.02	2	V	0.0	30.00	calc	
I	Proc	ess Type:	mine System	0										

Amine System – Performance input screen.

The amine-based absorption system for  $CO_2$  removal is a wet scrubbing operation. This process removes other acid gases and particulate matter in addition to  $CO_2$  from the flue gas. These are listed below along with additional performance parameters:

- **CO₂ Removal Efficiency:** Most studies report the CO₂ capture efficiency of the amine-based systems to be 90%, with few others reporting as high as 96% capture efficiency. Here, it has been assumed to be 90%.
- **SO₂ Removal Efficiency:** SO₂ is removed at a very high rate. The default efficiency is 99.5%.
- **SO₃ Removal Efficiency:** SO₃ is removed at a very high rate. The default efficiency is 99.5%.
- **NO₂ Removal Efficiency:** A small amount of NO₂ is removed. The default efficiency is 25%.
- **HCI Removal Efficiency:** HCl is removed at a high rate. The default efficiency is 95%.
- **Particulate Removal Efficiency:** Particulates are removed in any wet scrubbing system at a rate of approximately 50%.
- **Maximum Train CO₂ Capacity:** The default maximum train size is used with the actual CO₂ capture rate to determine the number of trains required.
- **Number of Operating Absorbers:** This is the total number of operating absorber vessels. It is determined by the train capacity specified above and is used primarily to calculate capital costs. The value must be an integer.
- **Number of Spare Absorbers:** This is the total number of spare absorber vessels. It is used primarily to calculate capital costs. The value must be an integer.

- **Max.**  $CO_2$  Compressor Capacity: This is the maximum amount of  $CO_2$  product that can be compressed per hour at the specified pressure (see the storage input screen).
- **No. of Operating CO₂ Compressors:** This is the total number of operating CO₂ compressors. It is used primarily to calculate capital costs. The value must be an integer.
- **No. of Spare CO₂ Compressors:** This is the total number of spare CO₂ compressors. It is used primarily to calculate capital costs. The value must be an integer.
- **Amine Scrubber Power Requirement:** This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical power required for pumps and booster fans.

# **Amine System Capture Inputs**

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.

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		Ove <u>r</u> all Plant	F <u>u</u> el	Base Plant Merce	ury <u>N</u> Ox Control	<u>T</u> Cor	SP S ttro1 Co	O2 ntrol	C <u>O</u> 2 Capture	By-Pr Mgr	od. nt St	ac <u>k</u>
9				Title	Units	Unc	Value	Calc	Min	Max	Default	
Ж		1	4	Absorber								
30	Ш	2	Sorbent Conc	entration	wt %		30.00		15.00	100.0	calc	
Ê.	Ш	3	Lean CO2 Los	ading	mol CO2/mol sorb		0.2000	V	0.0	0.5000	calc	
	Ш	4	Nominal Sorb	ent Loss	1b/ton CO2		3.000	V	0.0	10.00	calc	
	Ш	5	Sorbent Oxida	ation Loss	mol sorb/mol acid		1.000	V	0.0	2.000	calc	
<b>?</b> []	Ш	6	Liquid-to-Gas	Ratio	ratio		2.903	V	0.0	10.00	calc	
?	Ш	7	Ammonia Ger	neration	mol NH3/mol sorb		1.000	M	0.0	2.000	calc	
-	Ш	8	Gas Phase Pre	essure Drop	psia		2.000		0.0	5.000	2.000	
	Ш	9	ID Fan Efficie:	ncy	%		75.00		0.0	100.0	75.00	
	Ш	10										
	Ш	11	Re	egenerator								
	Ш	12	Regeneration	Heat Requirement	Btu/Ib CO2		1896	V	500.0	5000	calc	
		13	Steam Heat C	ontent	Btu/lb steam		860.4	V	500.0	1200	calc	
		14	Heat-to-Elects	icity Efficiency	%		14.00		0.0	40.00	calc	
		15	Solvent Pump	ing Head	psia		30.00		0.0	80.00	30.00	
		16	Pump Efficien	су	%		75.00		0.0	100.0	75.00	
	Ш	17	Percent Wate:	r in Reclaimer Waste	%		40.00	V	0.0	100.0	calc	
	Ш	18										
		Proc	ess Type: 🛛	mine System	-							
		<u>1</u> . Co:	nfig 🖌 <u>2</u> . P	erformance <u>3.</u> Ca	pture 🖌 4. CO2 S	torage	. <u>5</u> . Retro	it Cost	🖌 <u>6</u> . Capita	al Cost 🖌	7.0&MCa	ost

Amine System – Capture input screen.

### Absorber

The absorber is the vessel where the flue gas makes contact with the MEA-based sorbent, and some of the  $CO_2$  from the flue gas is dissolved in the sorbent. The column may be plate-type or a packed one. Most of the  $CO_2$  absorbers are packed columns using some kind of polymer-based packing to provide large interfacial area.

**Sorbent Concentration:** The solvent used for CO₂ absorption is a mixture of monoethanolamine (MEA) with water. MEA is a highly corrosive liquid, especially in the presence of oxygen and carbon dioxide, and hence needs to be diluted. Today the commercially available MEA-based technology supplied by Fluor Daniel uses 30%

w/w MEA solvent with the help of some corrosion inhibitors. Other suppliers, who do not use this inhibitor, prefer to use lower MEA concentrations in the range of 15%-20% by weight.

- **Lean CO₂ Loading:** Ideally, the solvent will be completely regenerated on application of heat in the regenerator section. Actually, even on applying heat, not all the MEA molecules are freed from CO₂. So, the regenerated (or lean) solvent contains some "left-over" CO₂. The level of lean solvent CO₂ loading mainly depends upon the initial CO₂ loading in the solvent and the amount of regeneration heat supplied, or alternatively, the regeneration heat requirement depends on the allowable level of lean sorbent loading.
- **Nominal Sorbent Loss:** MEA is a reactive solvent. In spite of dilution with water and use of inhibitors, a small quantity of MEA is lost through various unwanted reactions, mainly the polymerization reaction (to form long-chained compounds) and the oxidation reaction forming organic acids and liberating ammonia. It is assumed that 50 % of this MEA loss is due to polymerization and the remaining 50% of the MEA loss is due to oxidation to acids.
- **Sorbent Oxidation Loss:** The sorbent oxidation loss variable is a ratio of the number moles of sorbent that are lost for every mole of acid formed due to oxidation of the sorbent.
- **Liquid to Gas Ratio:** The liquid to gas ration is the ratio of total molar flow rate of the liquid (MEA sorbent plus water) to the total molar flow rate of flue gas being treated in the absorber.
- **Ammonia Generation:** The oxidation of MEA to organic acids (oxalic, formic, etc.) also leads to formation of NH₃. Each mole of MEA lost in oxidation, liberates a mole of ammonia (NH₃).
- **Gas Phase Pressure Drop:** This is the pressure drop that the flue gas has to overcome as it passes through a very tall absorber column, countercurrent to the sorbent flow.
- **ID Fan Efficiency:** The cooled flue gas is pressurized using a flue gas blower before it enters the absorber. This is the efficiency of the fan/blower to convert electrical power input into mechanical work output.

#### Regenerator

The regenerator is the column where the weak intermediate compound (carbamate) formed between the MEA-based sorbent and dissolved CO2 is broken down with the application of heat and  $CO_2$  gets separated from the sorbent to leave reusable sorbent behind. In case of unhindered amines like MEA, the carbamate formed is stable and it takes large amount of energy to dissociate. It also consists of a flash separator where  $CO_2$  is separated from most of the moisture and evaporated sorbent, to give a fairly rich  $CO_2$  stream.

- **Regeneration Heat Requirement:** This is the total amount of heat energy required in the reboiler for sorbent regeneration.
- **Steam Heat Content:** The regeneration heat is provided in the form of LP steam extracted from the steam turbine (in case of coal-fired power plants and combined-cycle gas plants), through the reboiler (a heat exchanger). In case of simple cycle natural gas fired power plants, a

heat recovery unit maybe required. This is the enthalpy or heat content of the steam used for solvent regeneration.

- **Heat to Energy Efficiency:** This is the efficiency of converting low pressure steam to electricity. The value reflects the loss of electricity to the base plant when the LP steam is used for regenerator heat.
- **Solvent Pumping Head:** The solvent has to flow through the absorber column (generally through packed media) countercurrent to the flue gas flowing upwards. So, some pressure loss is encountered in the absorber column and sufficient solvent head has to be provided to overcome these pressure losses. Solvent circulation pumps are used to provide the pressure head.
- **Pump Efficiency:** This is the efficiency of the solvent circulation pumps to convert electrical power input into mechanical power output.
- **Percent Water in Reclaimer Waste:** This is the amount of water typically present in the reclaimer waste.

## Amine System Storage Inputs

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.

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	Overall Plant     Fuel     Base Plant     Mercury     NOx Control     TSP Control     SO2 Control     CO2 Capture     Pyc-Prod. Mgmt       1     CO2 Product Stream		nd. St	ac <u>k</u>							
2			Title	Units	Unc	Value	Calc	Min	Max	Default	
111		1	CO2 Product Stream								
111		2	CO2 Product Pressure	psig		2000		0.0	4000	2000	
		3	CO2 Compressor Efficiency	%		80.00		0.0	100.0	80.00	
		4	CO2 Unit Compression Energy	kWh/ton CO2		107.0	M	0.0	180.0	calc	
		5									
111		6	CO2 Transport & Storage								
111		7	CO2 Storage Method:			Geologic		Menu	Menu	Geologic	
:		8									
111		9	Enhanced Oil Recovery (EOR)								
		10	Enhanced Coal Bed Methane (E								
		11	Geological Reservoir (Geologic)								
		12	Ocean (Ocean)								
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		Proc	ess Type: Amine System								
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Amine System – Storage input screen

This screen characterizes the compression and storage location for the product  $CO_2$ . A separate pipeline model is provided to specify inputs for that sub-system. The pipeline model is accessed from the **Process Type** menu at the bottom of the screen.

### **CO₂ Product Stream**

The concentrated CO₂ product stream obtained from sorbent regeneration is compressed and dried using a multi-stage compressor with inter-stage cooling.

- **Product Pressure:** The  $CO_2$  product may have to be carried over long distances. Hence it is necessary to compress (and liquefy) it to very high pressures, so that it maybe delivered to the required destination in liquid form and (as far as possible) without recompression facilities en route. The critical pressure for  $CO_2$  is about 1070 psig. The typically reported value of final pressure to which the product  $CO_2$  stream has to be pressurized using compressors, before it is transported is about 2000 psig.
- $CO_2$  Compressor Efficiency: This is the effective efficiency of the compressors used to compress  $CO_2$  to the desirable pressure.
- $CO_2$  Unit Compression Energy: This is the electrical energy required to compress a unit mass of  $CO_2$  product stream to the designated pressure. Compression of  $CO_2$  to high pressures requires substantial energy, and is a principle contributor to the overall energy penalty of a  $CO_2$  capture unit in a power plant.

#### CO₂ Transport & Storage

**Storage Method:** The default option for CO₂ disposal is underground geological storage.

- **EOR** Enhanced Oil Recovery
- **ECBM** Enhanced Coalbed Methane Recovery
- Geologic Geological Reservoir
- Ocean

# **Amine System Retrofit Cost Inputs**

This screen is only available for the Combustion (Boiler) and Combustion (Turbine) plant types.

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	Ove <u>r</u> all Plant	F <u>u</u> el	Base Plant	<u>M</u> ercu	uy <u>N</u> Ox Control	<u>T</u> S Con	SP S trol Co	02 ntrol	C <u>O</u> 2 Capture	By-Pr Mgi	od. nt S	tac <u>k</u>
			Title		Units	Unc	Value	Calc	Min	Max	Default	
Ш	1	<u>Capital</u> C	ost Process A:	rea								
Ш	2	Direct Contac	t Cooler		retro \$/new \$		1.000		0.0	10.00	1.000	
	3	Flue Gas Blov	ver		retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	4	CO2 Absorbe	r Vessel		retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	5	Heat Exchang	ers		retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	6	Circulation Pu	umps		retro \$/new \$		1.000		0.0	10.00	1.000	
	7	Sorbent Rege	nerator		retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	8	Reboiler			retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	9	Steam Extract	or		retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	10	Sorbent Recla	imer		retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	11	Sorbent Proc	essing		retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	12	CO2 Drying a	nd Compressio	n Unit	retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	13	Auxiliary Nat	ural Gas Boiler		retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	14	Auxiliary Stea	un Turbine		retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	15											
Ш	16											
Ш	17											
Ш	18											
	Proc	ess Type: 🛛	mine Systen	1	-							

Amine System – Retrofit Cost input screen

#### **Capital Cost Process Area**

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

The following are the **Capital Cost Process Areas** for the Amine System:

- **Direct Contact Cooler:** A direct contact cooler is typically used in plant configurations that do not include a wet FGD. A direct contact cooler is a large vessel where the incoming hot flue gas is placed in contact with cooling water. The cost is a function of the gas flow rate and temperature of the flue gas.
- **Flue Gas Blower:** The flue gas enters the bottom of the absorber column and flows upward, countercurrent to the sorbent flow. Blowers are required to overcome the substantial pressure drop as it passes through a very tall absorber column. The cost is a function of the volumetric flow rate of the flue gas.
- $CO_2$  Absorber Vessel: The capital cost of the absorber will go down with higher MEA concentration and higher CO₂ loading level of the solvent, and lower CO₂ content in the lean solvent. Therefore, a power law relationship based on flue gas flow rate is used. This is based on cost and flow rate data from Fluor Daniel, Inc. The cost assumes one absorber vessel per train. The cost is a function of the volumetric flow rate of the flue gas and the flue gas temperature.
- **Heat Exchangers:** The  $CO_2$ -loaded sorbent must be heated in order to strip off  $CO_2$  and regenerate the sorbent. In addition, the regenerated sorbent must be cooled down before it can be recirculated back to the absorber column. Heat exchangers are used to accomplish these two tasks. This area is a function of the sorbent flow rate.
- **Circulation Pumps:** Circulation pumps are required to take the sorbent, introduced at atmospheric pressure, and lift it to the top of the absorber column. This area is a function of the sorbent flow rate.
- **Sorbent Regenerator:** The regenerator (or stripper) is a column where the weak intermediate compound (carbamate) is broken down by the application of heat. The result is the release of  $CO_2$  (in concentrated form) and return of the recovered sorbent back to the absorber. This process is accomplished by the application of heat using a heat

exchanger and low-pressure steam. MEA requires substantial heat to dissociate the carbamate. Therefore a flash separator is also required, where the  $CO_2$  is separated from the moisture and evaporated sorbent to produce a concentrated  $CO_2$  stream. This area is a function of the sorbent flow rate.

- **Reboiler:** The regenerator is connected to a reboiler, which is a heat exchanger that utilizes low pressure steam to heat the loaded sorbent. The reboiler is part of the sorbent regeneration cycle. The cost is a function of the sorbent and steam flow rates.
- **Steam Extractor:** Steam extractors are installed to take low pressure steam from the steam turbines in the power plant. The cost is a function of the steam flow rate.
- **Sorbent Reclaimer:** A portion of the sorbent stream is distilled in the reclaimer in order to avoid accumulation of heat stable salts in the sorbent stream. Caustic is added to recover some of the MEA in this vessel. The reclaimer cost is a function of the sorbent makeup flow rate.
- **Sorbent Processing:** The sorbent processing area primarily consists of a sorbent cooler, MEA storage tank, and a mixer. The regenerated sorbent is further cooled with the sorbent cooler and MEA added to makeup for sorbent losses. This area is a function of the sorbent makeup flow rate.
- $CO_2$  Drying and Compression Unit: The product  $CO_2$  must be separated from the water vapor (dried) and compressed to liquid form in order to transport it over long distances. The multi-stage compression unit with inter-stage cooling and drying yields a final  $CO_2$ product at the nominal pressure of 2000 psig. This area is a function of the  $CO_2$  flow rate.
- **Auxiliary Natural Gas Boiler:** An auxiliary natural gas boiler is typically combined with a steam turbine to generate some additional power and/or low pressure steam. The cost is a function of the steam flow rate generated by the boiler. The boiler cost is lower if electricity is not being produced.
- **Auxiliary Steam Turbine:** The steam turbine is used in conjunction with the natural gas boiler to generate some additional power and/or low pressure steam. The cost is a function of the secondary power generated by the turbine.

# **Amine System Capital Cost Inputs**

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.

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3			Title		Units	Unc	Value	Calc	Min	Max	Default	
	1	Construction	Time		years		3.000		0.2500	10.00	3.000	
	2											
	3	General Facili	ties Capital		%PFC		10.00		0.0	50.00	10.00	
-	4	Engineering &	't Home Office Fees		%PFC		7.000		0.0	50.00	7.000	
	5	Project Contir	ngency Cost		%PFC		15.00		0.0	100.0	15.00	
111	6	Process Conti	ingency Cost		%PFC		5.000		0.0	100.0	5.000	
111	7	Royalty Fees			%PFC		0.5000		0.0	10.00	0.5000	
1	8											
	9	Pre-Pre	oduction Costs									
	10	Months of Fi	red O&M		months		1.000		0.0	12.00	1.000	
	11	Months of Va	riable O&M		months		1.000		0.0	12.00	1.000	
	12	Misc. Capital	Cost		%TPI		2.000		0.0	10.00	2.000	
	13											
	14	Inventory Ca	pital		%TPC		0.5000		0.0	10.00	0.5000	
	15											
	16											
	17		_									
	18	TCR Recover	y Factor		%		100.0		0.0	200.0	100.0	
	Proc	ess Type: 🛕	mine System		-							
	<u>1</u> . Co	nfig 🖌 <u>2</u> . P	erformance 🔬 <u>3</u> .	Capture	<u>4</u> .CO2	Storage	<u>5</u> . Retroi	it Cost	<u>6</u> . Capits	al Cost 🖌	7.0&MC	ost /

Amine System – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

**Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

- **General Facilities Capital (GFC)**: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

# Amine System O&M Cost Inputs

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	Ove <u>r</u> a Plant	11 ;	Fuel Base Plant Mercu	ury <u>N</u> Ox Control	<u>T</u> : Con	3P <u>S</u> .tro1 Co	CQ2 Capture Mgmt Stack				
	Г		Title	Units	Unc	Value	Calc	Min	Max	Default	
Ш	Γ	1	MEA Cost	\$/ton		1293		0.0	1.500e+04	calc	
Ш	Г	2	Inhibitor Cost	% of MEA		20.00		0.0	100.0	20.00	
Ш	Г	3	Activated Carbon Cost	\$/ton		1322		500.0	5000	calc	
Ш	Г	4	Caustic (NaOH) Cost	\$/ton		624.7		0.0	2000	calc	
Ш	Г	5	Water Cost	\$/1000 gai		0.8316		0.0	2.500	calc	
Ш		6									
Ш	Г	7	Reclaimer Waste Disposal Cost	\$/ton		188.6		0.0	300.0	calc	
Ш	Γ	8	Electricity Price (Base Plant)	\$/MWh		41.12		0.0	200.0	calc	
Ш		9	Number of Operating Jobs	jobs/shift		2.000		0.0	10.00	2.000	
Ш	Γ.	10	Number of Operating Shifts	shifts/day		4.750		0.0	10.00	4.750	
Ш		11	Operating Labor Rate	\$/hr		24.82		0.0	100.0	24.82	
Ш		12	Total Maintenance Cost	%TPC		2.500		0.0	10.00	2.500	
Ш		13	Maint. Cost Allocated to Labor	% total		40.00		0.0	100.0	40.00	
1		14	Administrative & Support Cost	% total labor		30.00		0.0	100.0	30.00	
		15									
11		16	CO2 Transport and Storage Costs								
		17	CO2 Transportation Cost	\$/ton		2.266	V	0.0	10.00	calc	
		18	CO2 Storage Cost	\$/ton		5.388		-150.0	60.00	calc	
II	P	roce	ess Type: Amine System	-		Costs are	in Con	stant 2005	5 dollars.		

Amine System – O&M Cost input screen.

Inputs for operation and maintenance are entered on the **O&M Cost** input. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below

**MEA Cost:** This is the unit cost of the makeup MEA.

- **Inhibitor Cost:** Addition of inhibitor makes it possible to use higher concentrations of MEA solvent in the system with minimal corrosion problems. Inhibitors are special compounds that come at a cost premium. The cost of inhibitor is estimated as a percent of the cost of MEA. The model default is 20%.
- Activated Carbon Cost: This is the cost of the activated carbon in \$ per ton.
- **Caustic (NaOH) Cost:** This is the cost of the caustic (NaOH) in \$ per ton.
- **Water Cost:** Water is mainly required for cooling and also as process makeup. Cost of water may vary depending upon the location of the power plant.
- **Natural Gas Cost:** This is the cost of the natural gas. *This is only visible if an auxiliary boiler is specified.*
- **Reclaimer Waste Disposal Cost:** The unit cost of waste disposal for the reclaimer waste.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)
- **Operating Labor Rate:** This is the hourly labor rate for operators working with the amine system. This is not used for maintenance, administrative, or support labor.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- **Maint. Cost Allocated to Labor:** Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

#### **CO2 Transport and Storage Costs**

- **CO₂ Transportation Cost:** Transportation of CO₂ product is assumed to take place via pipelines. This is the unit cost of CO₂ transport in \$/ton –mile. The cost is calculated from the pipeline sub-process model.
- $CO_2$  Storage Cost: This is the unit cost of  $CO_2$  disposal. Depending upon the method of  $CO_2$  disposal or storage, either there may be some revenue generated (Enhanced Oil Recovery, Coal Bed Methane) which may be treated as a "negative cost", or additional cost (all other disposal methods).

# **Amine System Diagram**

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



Amine System – Diagram.

#### Reagent

- **MEA Makeup:** The mass flow rate of fresh MEA needed to replace the amount used in the process.
- Water: This is the flow rate of water that is used to mix with the MEA Makeup.

#### Flue Gas Entering Amine System

- **Temperature In:** Temperature of the flue gas entering the amine system area, prior to any processing. This is determined by the flue gas outlet temperature of the process area upstream.
- Flue Gas In: Volumetric flow rate of flue gas entering the amine system.
- **Fly Ash In:** Total solids mass flow rate in the flue gas entering the Amine System. This is determined by the solids exiting from the module upstream.
- **Mercury In:** Total mass of mercury entering the amine system. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).
- **Temperature:** Temperature of the flue gas entering the amine scrubber system.
- Water: This is the flow rate of water into the Direct Contact Cooler.

#### Flue Gas Exiting Amine System

- **Temperature Out:** Temperature of the flue gas exiting the amine scrubber system.
- Flue Gas Out: Volumetric flow rate of the flue gas exiting the amine scrubber.
- **Fly Ash Out:** Total solids mass flow rate in the flue gas exiting the amine scrubber.
- **Mercury Out:** Total mass of mercury exiting the amine scrubber. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

#### **Amine System Performance**

- **NH₃ Generation:** The flow rate of ammonia by product produced in the amine scrubbing process.
- **CO₂ Removal:** Actual removal efficiency of CO₂ in the amine scrubber.
- **Sorbent Circ.:** The flow rate of the sorbent through the amine scrubber system.
- **CO₂ Product:** Actual amount of CO₂ produced as a result of the amine scrubbing.
- **CO₂ Pressure:** Compressed CO₂ product pressure. The product stream is compressed and sent through the pipeline system to the configured sequestration system.

### **Collected Solids**

**Reclaimer Waste:** Total solids mass flow rate of solids removed from the amine scrubber.

# **Amine System Flue Gas Results**

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.

Cor	foure Plant	et Parameter	s ľ		let Results	
<u>_</u> 0		et <u>i</u> arameter	°		Jet Kestuts	
Overall Plant	Fuel <u>B</u> oiler <u>Air</u> <u>N</u> Ox Preheater Control	Mercury	<u>T</u> SP <u>S</u> Control Cor	D2 C <u>O</u> 2 ntrol Captu	re <u>M</u> gmt	Stac
	Major Flue Gas Components	Flue Gas In (Ib-moles/hr)	Flue Gas Out (lb-moles/hr)	Flue Gas In (ton/hr)	Flue Gas Out (ton/hr)	
1	Nitrogen (N2)	1.266e+05	1.266e+05	1773	1773	
2	Oxygen (O2)	9379	9379	150.1	150.1	
3	Water Vapor (H2O)	2413	2413	21.74	21.74	
4	Carbon Dioxide (CO2)	2.050e+04	2050	451.0	45.10	
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	
6	Hydrochloric Acid (HCl)	5.643	0.2821	0.1029	5.144e-03	
7	Sulfur Dioxide (SO2)	41.12	0.2056	1.317	6.586e-03	
8	Sulfuric Acid (equivalent SO3)	1.468e-02	7.338e-05	5.875e-04	2.937e-06	
9	Nitric Oxide (NO)	10.99	10.99	0.1649	0.1649	
10	Nitrogen Dioxide (NO2)	0.5783	0.4338	1.330e-02	9.979e-03	
11	Ammonia (NH3)	0.7392	145.1	6.294e-03	1.236	
12	Argon (Ar)	0.0	0.7500	0.0	1.498e-02	
13	Total	1.589e+05	1.406e+05	2397	1991	
14						
15						

Amine System – Flue Gas result screen

#### **Major Flue Gas Components**

Each result is described briefly below:

Nitrogen (N2): Total mass of nitrogen.

Oxygen (O2): Total mass of oxygen.

Water Vapor (H2O): Total mass of water vapor.

Carbon Dioxide (CO2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.

Ammonia (NH3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **Amine System Capital Cost Results**

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.
U	ntit		<i>d</i>	_			
		Configure Plant	Set I	ara	ame	ters <u>G</u> et R	esults
O' F	ze <u>r</u> : 1an	all Fuel <u>B</u> oiler <u>A</u> ir rPreheater	NOx Control	<u>M</u> erc	ury	Image: TSP     SO2     CO2     B       Control     Control     Capture     B	y-Prod. Mgmt Stac <u>k</u>
		MEA Scrubber Process Area Costs	Capital Co (M\$)	st		MEA Scrubber Plant Costs	Capital Cost (M\$)
	ı I	Direct Contact Cooler	12.51		1	Process Facilities Capital	135.0
	2	Flue Gas Blower	2.478		2	General Facilities Capital	13.50
	3	CO2 Absorber Vessel	35.02		3	Eng. & Home Office Fees	9.448
1	1	Heat Exchangers	2.545		4	Project Contingency Cost	20.25
	5	Circulation Pumps	5.243		5	Process Contingency Cost	6.748
	6	Sorbent Regenerator	19.20		6	Interest Charges (AFUDC)	19.70
	7	Reboiler	11.72		7	Royalty Fees	0.6748
	8	Steam Extractor	1.188		8	Preproduction (Startup) Cost	14.90
	9	Sorbent Reclaimer	7.966		9	Inventory (Working) Capital	0.9245
1	0	Sorbent Processing	10.25		10	Total Capital Requirement (TCR)	221.1
1	1	Drying and Compression Unit	26.84		11		
1	2	Auxiliary Natural Gas Boiler	0.0		12		
1	3	Auxiliary Steam Turbine	0.0		13		
1	4	Process Facilities Capital	135.0		14		
]	5				15	Effective TCR	221.1
I	'no	cess Type: Amine System	-			Costs are in Constant 2005 dollars.	

Amine System – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

### **MEA Scrubber Process Area Costs**

- **Direct Contact Cooler:** This area includes the equipment required to cool the flue gas in order to improve absorption of  $CO_2$  into the amine sorbent. In case of coal-fired power plant applications that have a wet FGD (flue gas desulfurization) unit upstream of the amine system, the wet scrubber helps in substantial cooling of the flue gases, and additional cooler may not be required.
- **Flue Gas Blower:** The flue gas has to overcome a substantial pressure drop as it passes through a very tall absorber column, countercurrent to the sorbent flow. Hence the cooled flue gas has to be pressurized using a blower before it enters the absorber.
- **CO2** Absorber Vessel: This is the vessel where the flue gas is made to contact with the MEA-based sorbent, and some of the  $CO_2$  from the flue gas gets dissolved in the sorbent. The column may be plate-type or a packed one. Most of the  $CO_2$  absorbers are packed columns using some kind of polymer-based packing to provide large interfacial area.
- **Heat Exchangers:** The  $CO_2$ -loaded sorbent needs to be heated in order to strip off  $CO_2$  and regenerate the sorbent. On the other hand, the regenerated (lean) sorbent coming out of the regenerator has to be cooled down before it could be circulated back to the absorber column. Hence these two sorbent streams are passed through a cross heat exchanger, where the rich ( $CO_2$ -loaded) sorbent gets heated and the lean (regenerated) sorbent gets cooled.

- **Circulation Pumps:** The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.
- **Sorbent Regenerator:** This is the column where the weak intermediate compound (carbamate) formed between the MEA-based sorbent and dissolved  $CO_2$  is broken down with the application of heat and  $CO_2$  gets separated from the sorbent to leave reusable sorbent behind. In case of unhindered amines like MEA, the carbamate formed is stable and it takes large amount of energy to dissociate. It also consists of a flash separator where  $CO_2$  is separated from most of the moisture and evaporated sorbent, to give a fairly rich  $CO_2$  stream.
- **Reboiler:** The regenerator is connected with a reboiler which is basically a heat exchanger where low-pressure steam extracted from the power plant is used to heat the loaded sorbent
- **Steam Extractor:** In case of coal-fired power plants that generate electricity in a steam turbine, a part of the LP/IP steam has to be diverted to the reboiler for sorbent regeneration. Steam extractors are installed to take out steam from the steam turbines.
- **Sorbent Reclaimer:** Presence of acid gas impurities (SO₂, SO₃, NO₂ and HCl) in the flue gas leads to formation of heat stable salts in the sorbent stream, which can not be dissociated even on application of heat. In order to avoid accumulation of these salts in the sorbent stream and to recover some of this lost MEA sorbent, a part of the sorbent stream is periodically distilled in this vessel. Addition of caustic helps in freeing of some of the MEA. The recovered MEA is taken back to the sorbent stream while the bottom sludge (reclaimer waste) is sent for proper disposal.
- **Sorbent Processing:** The regenerated sorbent has to be further cooled down even after passing through the rich/lean cross heat exchanger using a cooler, so that the sorbent temperature is brought back to acceptable level (about 40 deg C). Also, in order to make up for the sorbent losses, a small quantity of fresh MEA sorbent has to be added to the sorbent stream. So, the sorbent processing area primarily consists of sorbent cooler, MEA storage tank, and a mixer. It also consists of an activated carbon bed filter that adsorbs impurities (degradation products of MEA) from the sorbent stream.
- **Drying and Compression Unit:** The  $CO_2$  product may have to be carried to very long distances via pipelines. Hence it is desirable that it does not contain any moisture in order to avoid corrosion in the pipelines. Also, it has to be compressed to very high pressures so that it gets liquefied and can overcome the pressure losses during the pipeline transport. The multi-stage compression unit with inter-stage cooling and drying yields a final  $CO_2$  product at the specified pressure (about 2000 psig) that contains moisture and other impurities (e.g. N₂) at acceptable levels.
- **Auxiliary Natural Gas Boiler:** The cost of the natural gas boiler is estimated on the basis of the steam flow rate generated from the auxiliary boiler.
- **Auxiliary Steam Turbine:** The regeneration heat is provided in the form of low pressure (LP) steam extracted from the steam turbine (in case of coal-fired power plants and combined-cycle gas plants), through the

reboiler (a heat exchanger). In case of simple cycle natural gas fired power plants, a heat recovery unit maybe required.

**Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

### **MEA Scrubber Plant Costs**

Process Facilities Capital: (see definition above)

- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

## Amine System O&M Cost Results

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.

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١ſ			<u>C</u> onfigure	e Plant	Ĩ	Se	et <u>P</u> ar	ame	ters	Ĩ	Get	Results	
	(	Ove <u>r</u> Plar	all F <u>u</u> el	Boiler	<u>A</u> ir Preheater	<u>N</u> Ox Control	Mei	cury	<u>T</u> SP Control	<u>S</u> O2 Control	C <u>O</u> 2 Capture	By-Prod. Mgmt	Stac <u>k</u>
			Variabl	e Cost Com	ponent	O&M (M\$/;	Cost (r)		Fi	xed Cost Co	mponent	80 ()	ìM Cost A\$∕yr)
I		1	Sorbent			44.6	4	1	Operating L	abor		0	.6025
Ш		2	Natural Gas			0.0		2	Maintenanc	e Labor		1	1.849
II		3	Corrosion Inhibi	itor		8.92	9	3	Maintenanc	e Material		2	2.774
II		4	Activated Carbo	on		0.26	52	4	Admin. & S	upport Labor	r	0	.7355
II		5	Caustic (NaOH)			0.21	72	5	Total Fixed	Costs		6	5.961
II		6	Reclaimer Waste	e Disposal		13.2	6	6					
II		7	Electricity			15.2	9	7					
		8	Auxiliary Power	Credit		0.0		8					
II		9	Steam (elec. equ	iv.)		20.5	3	9					
II		10	Water			6.6836	9-02	10					
II		11	CO2 Transport			6.08	2	11					
II		12	CO2 Storage			14.4	6	12					
II		13	Total Variable C	osts		123.	7	13					
I		14						14					
I		15						15	Tetal O&M	Costs		1	.29.7
I		Pro	cess Type: Ar	nine Syste	em	•			Costs ar	e in Constan	ıt 2005 dolla	ırs.	
1	K	1	Diagram /	2 Flue Gas	/ 3 B		4 Com	tol Co	at 5.08	M.Coat	6 Total Co.	at / 7	Miss

Amine System – O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **CO**₂ **Capture** technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

### **Variable Cost Components**

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

- **Sorbent:** MEA is the default sorbent used in the system and this is the annual cost of the MEA. This is a function of the concentration of CO2 in the flue gas and the flue gas flow rate.
- **Natural Gas:** If the user has added an auxiliary natural gas boiler, the cost of the natural gas used to fuel the boiler is added here.
- **Corrosion Inhibitor:** The inhibitor helps in two ways reduced sorbent degradation and reduced equipment corrosion. This is the annual cost of the corrosion inhibitor.
- Activated Carbon: This is the cost of activated carbon used to adsorb impurities from the sorbent (degradation products of MEA).
- **Caustic (NaOH):** This is the annual cost of caustic. The presence of acid gas impurities (SO₂, SO₃, NO₂ and HCl) in the flue gas leads to formation of heat stable salts in the sorbent stream, which can not be

dissociated even on application of heat. In order to avoid accumulation of these salts in the sorbent stream and to recover some of this lost MEA sorbent, a part of the sorbent stream is periodically distilled in this vessel. Addition of caustic helps in freeing of some of the MEA. The recovered MEA is taken back to the sorbent stream while the bottom sludge (reclaimer waste) is sent for proper disposal.

- **Reclaimer Waste Disposal:** This is the reclaimer waste disposal cost per year.
- Electricity: The cost of electricity consumed by the Amine System.
- **Auxiliary Power Credit:** An auxiliary natural gas boiler can be added by the user to provide steam and power for the Amine System. If it is added by the user then the additional power it provides is subtracted from the overall operating and maintenance cost.
- **Steam (elec. equiv.):** Cost of steam used in the regeneration of the sorbent. This is a cost that is incurred only when steam is taken from the base plant.
- **Water:** This is the annual cost for water to the amine scrubber system; it is mainly required for cooling and also as process makeup.
- $CO_2$  Transport: The CO₂ captured at the power plant site has to be carried to the appropriate storage/ disposal site. Transport of CO₂ to a storage site is assumed to be via pipeline. This is the annual cost of maintaining those pipelines.
- **CO₂ Storage:** Once the CO₂ is captured, it needs to be securely stored (sequestered). This cost is based upon the storage option chosen on the Amine System Storage input screen.
- **Total Variable Costs:** This is the sum of the variable O&M costs listed above. This result is highlighted in yellow.

### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

**Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

### **Amine System Total Cost Results**

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.

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	ĺ	Overall Plant	F	'uel <u>B</u> oiler <u>A</u> ir <u>N</u> Ox Preheater Contro	1 Mercury	TSP Control Co	02 CO2 ntrol Captu	re By-Prod. Mgmt	Stack
*				Cost Component	M\$/yr	\$/MWh	\$/ton CO2 captured	Percent Total	
			1	Annual Fixed Cost	5.961	2.648	2.229	3.670	
P			2	Annual Variable Cost	123.7	54.97	46.27	76.18	
			3	Total Annual O&M Cost	129.7	57.61	48.50	79.85	
			4	Annualized Capital Cost	32.72	14.54	12.24	20.15	
$\mathbb{P}_{\mathbb{Z}}$			5	Total Levelized Annual Cost	162.4	72.15	60.73	100.0	
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		Process	Туре	· Amine System	-	Costs are in C	onstant 2005 d	ollars.	
		<u>1</u> . Diag	ram	<u>2. Flue Gas</u> <u>3</u> . Bypass		<u>∕</u> <u>5</u> .0&M C₀	st 🛕 <u>6</u> . Total	Cost <u>7</u> . N	Aisc.

Amine System – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Amine System**  $CO_2$  **Control** technology. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

### **Cost Component**

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

**Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

### **Amine System Cost Factors Results**

This screen is only available for the Combustion (Boiler) and Combustion (Turbine) plant types.

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<i>∰</i> ∦ ₽			Important Performance and Cost Factors	Value		Cost of CO2 Avoided	Value
C.	Ш	1	Net Electrical Output (MW)	331.8	1	Capture Plant	
r B	Ш	2	Annual Operating Hours (hours)	6575	2	CO2 Emissions (lbs/kWh)	0.2770
	Ш	3	Annual CO2 Removed (tons/yr)	2.720e+06	3	Cost of Electricity (\$/MWh)	107.3
•	Ш	4	Annual SO2 Removed (tons/yr)	905.9	4		
	Ш	5	Annual SO3 Removed (tons/yr)	171.2	5	<u>Reference Plant</u>	
<u> ?</u> ]	Ш	6	Annual NO2 Removed (tons/yr)	103.7	6	CO2 Emissions (lbs/kWh)	0.0
?	Ш	7	Annual HC1 Removed (tons/yr)	64.83	7	Cost of Electricity (\$/MWh)	0.0
١Ľ	Ш	8	Flue Gas Fan Use (MW)	11.68	8		
	Ш	9	Sorbent Pump Use (MW)	0.8939	9	Cost of CO2 Avoided (\$/ton)	-774.3
	Ш	10	CO2 Compression Use (MW)	44.26	10		
	Ш	11	Aux. Power Produced (MW)	0.0	11		
	Ш	12	Sorbent Regeneration Equiv. Energy (MW)	64.40	12		
	Ш	13			13		
	Ш	14	Fixed Charge Factor (fraction)	0.1480	14		
	Ш	15			15		
		Pro	cess Type: Amine System	-		Costs are in Constant 2005 dollars.	
			. Diagram 🖌 2. Flue Gas 🖌 3. Bypa	ss 🖌 <u>4</u> . Capi	tal Co	st 🖌 <u>5</u> .0&M Cost 🖌 <u>6</u> . Total Cost 🗼	7. Mise.

Amine System – Cost Factors result screen.

### **Important Performance and Cost Factors**

This screen displays information that is key to the model calculations. The data is available else where in the model.

- **Net Plant Size (MW):** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).
- **Annual Operating Hours (hours):** This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.
- **Annual CO₂ Removed (ton/yr):** This is thel amount of CO₂ removed from the flue gas by the CO₂ capture system per year.
- **Annual SO₂ Removed (ton/yr):** This is the amount of SO₂ removed from the flue gas by the  $CO_2$  capture system per year.
- **Annual SO₃ Removed (ton/yr):** This is the amount of SO₃ removed from the flue gas by the  $CO_2$  capture system per year.

- **Annual NO₂ Removed (ton/yr):** This is the amount of NO₂ removed from the flue gas by the CO₂ capture system per year.
- **Annual HCI Removed (ton/yr):** This is the amount of HCl removed from the flue gas by the  $CO_2$  capture system per year.
- Flue Gas Fan Use (MW): The flue gas has to be compressed in a flue gas blower so that it can overcome the pressure drop in the absorber tower. This is the electrical power required by the blower.
- **Sorbent Pump Use (MW):** The solvent has to flow through the absorber column (generally through packed media) countercurrent to the flue gas flowing upwards. This is the power required by the solvent circulation pumps to supply pressure to overcome the pressure losses encountered by the solvent in the absorber column.
- $CO_2$  Compression Use (MW): This is the electrical power required to compress the CO₂ product stream to the designated pressure. Compression of CO₂ to high pressures takes lot of power, and is a principle contributor to the overall energy penalty of a CO₂ capture unit in a power plant.
- **Aux. Power Produced (MW):** If an auxiliary natural gas boiler is used to provide steam and power for the Amine System, this is the additional electricity that it produces.
- **Sorbent Regeneration Equiv. Power (MW):** This is the electrical equivalent power for the regeneration steam required (taken from the steam cycle). The equivalent electricity penalty is about 10-15% of the actual regeneration heat requirement.
- **Fixed Charge Factor (fraction):** The fixed charge factor is one of the most important parameters in the IECM. It determines the revenue required to finance the power plant based on the capital expenditures. Put another way, it is a levelized factor which accounts for the revenue per dollar of total plant cost that must be collected from customers in order to pay the carrying charges on that capital investment.

### Cost of CO₂ Avoided

Many analysts like to express the cost of an environmental control system in terms of the cost per ton of pollutant removed or avoided. For energy-intensive  $CO_2$  controls there is a big difference between the cost per ton  $CO_2$  removed and the cost per ton "avoided" based on *net* plant capacity. Since the purpose of adding a  $CO_2$  unit is to reduce the  $CO_2$  emissions per net kWh delivered, the cost of  $CO_2$  avoidance is the economic indicator that is widely used in this field.

#### **Capture Plant**

- **CO2 Emissions (lb/kWh):** This is the amount of CO2 vented to the air for every kilowatt hour of electricity produced in the power plant that is using **CO2 Capture Technology**.
- **Cost of Electricity (\$/MWh):**The IECM framework calculates the cost of electricity (COE) for the overall **Capture Plant** by dividing the total annualized plant cost (\$/yr) by the net electricity generated (kWh/yr)

#### **Reference Plant**

- **CO2 Emissions (lb/kWh):** This is the amount of CO2 vented to the air for every kilowatt hour of electricity produced in the power plant with **NO CO2 Capture**.
- **Cost of Electricity (\$/MWh):**The IECM framework calculates the cost of electricity (COE) for the overall **Reference Plant** by dividing the total annualized plant cost (\$/yr) by the net electricity generated (kWh/yr)
- **Cost of CO₂ Avoided (\$/ton):** This is the economic indicator widely used in the field, calculated as the difference between the cost of electricity in the capture plant and the reference plant divided by the difference between the CO2 emissions in the reference plant and the capture plant. Cost of CO2 Avoided =

(Cost of Electricity cap. – Cost of Electricity ref.)

/ (CO2 emissions ref. – CO2 emissions cap.)

# O₂-CO₂ Recycle

The  $O_2$ - $CO_2$  Recycle is a post-combustion technology used for  $CO_2$  capture. It is more frequently referred to as "oxyfuel" combustion. Two systems are associated with this technology, **Air Separation** and **Flue Gas Recycle**. The following sections describe the performance and result screens for each of these systems. The  $O_2$ - $CO_2$  Recycle option is available in the IECM in the Combustion (Boiler) plant type configuration.

Please refer to the air separation chapter for help with the oxidant feed input parameters and results.

# O₂-CO₂ Recycle Configuration

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8			Title		Units	Unc	Value	Calc	Min	Max	Default	
Å		1	Is this a Retrofit Unit?				No 🔻		Menu	Menu	No	
8		2										
E.		3										
P		4	Reference Plant									
		6	(Inputs for Avoidance Cost	Calc.)								
		7	CO2 Emission Rate		lbs/kWh		0.0	M	0.0	5.000	calc	
		8	Cost of Electricity		\$/MWh		0.0	M	0.0	150.0	calc	
2		9										
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This screen is available for Combustion (Boiler) plant types.

O₂-CO₂ Recycle Flue Gas – Configuration input screen.

**Is this a Retrofit Unit?** The user may decide whether the unit is added to a new or existing plant.

**Reference Plant** 

The following reference plant inputs are used to determine the avoided cost of  $CO_2$  avoidance. The default value is zero for both parameters, requiring the user to supply the actual reference plant values. Reference values can be obtained by simulating the same plant configuration minus the  $CO_2$  capture. Analysts commonly express the cost of an environmental control system in terms of either the cost per ton of pollutant removed or the cost per ton "avoided." For an energy-intensive system like amine scrubbers there is a big difference between the cost per ton  $CO_2$  removed and the cost per ton  $CO_2$  avoided based on *net* plant capacity. Since the purpose of adding a capture unit is to reduce the  $CO_2$  emissions per net kWh delivered, the cost of  $CO_2$  avoidance (relative to a reference plant with no  $CO_2$  control) is the economic indicator most widely used. The reference plant used to compare to the actual plant must be defined as follows:

**CO₂ Emission Rate:** This is the emission rate for the reference power plant (without CO₂ capture)

**Cost of Electricity:** This is the cost of electricity for the reference power plant (without CO₂ capture)

### O₂-CO₂ Recycle Performance Inputs

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		Title	Units	Unc	Value	Calc	Min	Max	Default
	1	Flue Gas Recycle Stream							
	2	Flue Gas Recycled	%		70.00		60.00	85.00	70.00
11	3	Oxygen Content in Air/Oxidant	vo1 %		29.35	V	0.0	100.0	calc
11	4	Particulate Removal Efficiency	%		50.00		0.0	100.0	50.00
	5	Flue Gas Cooling Power Requirem	% MWg		0.8668	V	0.0	15.00	calc
	6	Recycled Gas Temperature	°F		100.0		60.00	350.0	100.0
	7	Recycle Fan Pressure Head	psia		0.1400		0.0	2.000	0.1400
	8	Recycle Fan Efficiency	%		75.00		0.0	100.0	75.00
	9	Flue Gas Recycle Power Requirem	% MWg		4.785e-02	V	0.0	15.00	calc
	10								
	11	Flue Gas Purification Unit							
	12	Is Flue Gas Purification Present?			Yes 🔻		Menu	Menu	Yes
	13	CO2 Capture Efficiency	%		90.00	2	0.0	100.0	calc
Π	14	CO2 Product Purity	%		97.50	V	90.00	100.0	calc
Π	15	CO2 Unit Purification Energy	kWh/ton CO2		18.00	V	0.0	1000	calc
	16	CO2 Purification Energy	% MWg		1.397	V	0.0	15.00	calc
	17								
	18								
	Proc	ess Type: FG Recycle & Purific	cation 💌						
	<u>1</u> .0	onfig <u>2</u> . Performance	<u>3</u> . CO2 Storage /	<u>4</u> . F	Retrofit Cost	1 2	. Capital Co	st / !	<u>6</u> . O&M Cost /

This screen is available for Combustion (Boiler) plant types.

 $O_2$ - $CO_2$  Recycle Flue Gas – Performance input screen.

#### Flue Gas Recycle Stream

- Flue Gas Recycled: This is the percentage of the total flue gas that is to be recycled
- **Oxygen Content in Air/Oxidant:** This is the volume percent that is oxygen.
- Particulate Removal Efficiency: This is the percentage of particulates that are removed by the Flue Gas Recycle system.

- Flue Gas Cooling Power Requirement: This is the percentage of the total gross power of the plant required to cool the flue gas being recycled.
- **Recycled Gas Temperature:** This is the temperature of the recycled flue gas.
- **Recycle Fan Pressure Head:** A fan is used to provide a small pressure head for the recycled flue gas stream going back to the boiler. This FGR fan pressure head along with the recycled flue gas flow rate, determine the power used by the fan.
- **Recycle Fan Efficiency:** This is the efficiency of the fan converting electrical power input into mechanical work output.
- Flue Gas Recycle Power Requirement: This is the percentage of the total gross power of the plant required to recycle the flue gas.

#### Flue Gas Purification Unit

- **Is Flue Gas Purification Present?:** The user may add a flue gas purification system.
- **CO₂ Capture Efficiency:** This is the percentage of the CO₂ which the system is able to capture.
- **CO₂ Product Purity:** This is the percentage of the product that is carbon dioxide.
- $CO_2$  Unit Purification Energy: This is the energy required for one unit to purify the  $CO_2$  product per ton purified.
- **CO₂ Purification Energy:** This is the total energy required to purify the CO₂ product.

# O₂-CO₂ Recycle CO₂ Storage Inputs

This screen is available for Combustion (Boiler) plant types.

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3	Γ		Title		Units	Unc	Value	Calc	Min	Max	Default	
8		1	CO2 Compre	ession								
<u> </u>		2	CO2 Product Pressur	e	psig		2000		1100	2200	2000	
		3	CO2 Compressor Effi	ciency	%		80.00		75.00	85.00	80.00	
		4	Unit CO2 Compressio	on Energy	kWh/ton CO2		107.0	M	0.0	180.0	calc	
		5	Total CO2 Compressi	ion Energy	% MWg		8.302	Ľ	0.0	15.00	calc	
		6										
		7	CO2 Transport d	& Storage								
		8	CO2 Storage Method	l:			Geologic		Menu	Menu	Geologic	
		9	Enhanced Oil Recov	ery (EOR)								
?		10	Enhanced Coal Bed	Methane (E								
		11	Geological Reservoi	r (Geologic)								
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 $O_2$ - $CO_2$  Recycle Flue Gas –  $CO_2$  storage input screen.

#### CO2 Compression

The concentrated CO₂ product stream obtained from sorbent regeneration is compressed and dried using a multi-stage compressor with inter-stage cooling.

- $CO_2$  Product Pressure: The CO₂ product may have to be carried over long distances. Hence it is necessary to compress (and liquefy) it to very high pressures, so that it maybe delivered to the required destination in liquid form and (as far as possible) without recompression facilities en route. The critical pressure for CO₂ is about 1070 psig. The typically reported value of final pressure to which the product CO₂ stream has to be pressurized using compressors, before it is transported is about 2000 psig.
- $CO_2$  Compressor Efficiency: This is the effective efficiency of the compressors used to compress  $CO_2$  to the desirable pressure.
- **Unit CO₂ Compression Energy:** This is the electrical energy required to compress a unit mass of  $CO_2$  product stream to the designated pressure. Compression of  $CO_2$  to high pressures requires substantial energy, and is a principle contributor to the overall energy penalty of a  $CO_2$  capture unit in a power plant.
- **Total CO₂ Compression Energy:** This is the electrical energy required to compress the CO₂ product stream to the designated pressure, given as a percent of the total gross power generated by the power plant. Compression of CO₂ to high pressures requires substantial energy, and is a principle contributor to the overall energy penalty of a CO₂ capture unit in a power plant.

#### CO2 Transport & Storage

- **CO₂ Storage Method:** The following are the optional methods for CO₂ disposal. The default option for CO₂ disposal is underground geological storage.
  - Enhanced Oil Recovery (EOR)
  - Enhanced Coal Bed Methane (ECBM)
  - Geological Reservoir (Geologic)
  - Ocean (Ocean)

### O₂-CO₂ Recycle Retrofit Cost Inputs

This screen is available for Combustion (Boiler) plant types.

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	O I	ve <u>r</u> all Plant	Fuel	Base Plant	Mercu	ma 🔪	<u>N</u> Ox Control	<u>T</u> S Con	sP trol Co	<u>3</u> O2 ontrol	C <u>O</u> 2 Capture	By-Pr Mgi	rod. mt Si	ac <u>k</u>
				Title		U	nits	Unc	Value	Calc	Min	Max	Default	
11		1	Capital C	Cost Process A:	rea									
111		2	Boiler Modifi	cations		retro	\$/new \$		1.000		0.0	10.00	1.000	
111		3	Flue Gas Rec	ycle Fan		retro	\$/new \$		1.000		0.0	10.00	1.000	
11		4	Flue Gas Rec	ycle Ducts		retro	\$/new \$		1.000		0.0	10.00	1.000	
Ш		5	Oxygen Heat	er		retro	\$/new \$		1.000		0.0	10.00	1.000	
11		6	Direct Contac	ct Cooler		retro	\$/new \$		1.000		0.0	10.00	1.000	
111		7	CO2 Compres	ssion System		retro	\$/new \$		1.000		0.0	10.00	1.000	
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O₂-CO₂ Recycle Flue Gas – Retrofit cost input screen.

#### **Capital Cost Process Area**

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

The following are the **Capital Cost Process Areas** for the **Flue Gas Recycle** portion of the plant:

- **Boiler Modifications:** In case of a *pre-existing* PC plant being retrofitted for  $CO_2$  capture, the boiler must be modified to suit the new oxyfuel combustion system. The cost for these modifications is estimated as a percentage of the cost of the boiler
- **Flue Gas Recycle Fan:** The cost of the fan required for recycling part of the flue gas is scaled on the basis of the flow rate of the flue gas being recycled
- Flue Gas Recycle Ducts: Additional ducting is necessary to recycle part of the flue gas in the oxyfuel combustion system. The cost of this

ducting is assumed to be a function of the flow rate of recycled flue gas.

- **Oxygen Heater:** In addition to the air preheater that exists in a conventional PC plant, the oxyfuel combustion system includes an additional heat exchanger called the "oxygen heater" for better heat integration. The cost of this heat exchanger is scaled on the basis of the gross plant size
- **Direct Contact Cooler:** The cost of the flue gas cooler is scaled on the basis of the flow rate of the flue gas.
- $CO_2$  Compression System: The multi-stage compression unit with inter-stage cooling and drying yields the final CO₂ product at the specified pressure (about 2000 psig) that contains only acceptable levels of moisture and other impurities (e.g. N₂) The size (and cost) of this unit will be a function of the CO₂ product compression power.

# O₂-CO₂ Recycle Capital Cost Inputs

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	Ove <u>r</u> all Plant	Fuel Base Plant	<u>M</u> ercu	ry <u>N</u> Ox Control	<u>T</u> S Con	SP S trol Co	O2 ntro1	C <u>O</u> 2 Capture	By-Pr Mgi	od. nt St	ac <u>k</u>
		Title		Units	Unc	Value	Calc	Min	Max	Default	
	1	Construction Time		years		2.500		0.0	10.00	2.500	
	2										
	3	General Facilities Capital		%PFC		10.00		0.0	50.00	10.00	
	4	Engineering & Home Office I	Fees	%PFC		7.000		0.0	50.00	7.000	
	5	Project Contingency Cost		%PFC		15.00		0.0	100.0	15.00	
	6	Process Contingency Cost		%PFC		5.000		0.0	100.0	5.000	
	7	Royalty Fees		%PFC		0.5000		0.0	10.00	0.5000	
	8										
	9	Pre-Production Costs									
	10	Months of Fixed O&M		months		1.000		0.0	12.00	1.000	
	11	Months of Variable O&M		months		1.000		0.0	12.00	1.000	
	12	Misc. Capital Cost		%TPI		2.000		0.0	10.00	2.000	
	13										
	14	Inventory Capital		%TPC		0.5000		0.0	10.00	0.5000	
	15										
	16										
	17										
	18	TCR Recovery Factor		%		100.0		0.0	200.0	100.0	
	Proc	ess Type: FG Recycle &	Purifica	ation 💌							
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This screen is available for Combustion (Boiler) plant types.

*O*₂-*CO*₂ *Recycle Flue Gas – Capital cost input screen.* 

Inputs for capital costs are entered on the **Capital Cost** input screen.

**Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

**General Facilities Capital (GFC)**: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.

**Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to

the architect/engineering company. These fees typically range from 7-15%.

- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.
  - **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
  - **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
  - **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

### O₂-CO₂ Recycle O&M Cost Inputs

This screen is available for Combustion (Boiler) plant types.

	(	Configure I	Plant	Ĩ	Set Par	amete	ers	Ĩ		Get Res	ults
Ove Pla	- rall nt	F <u>u</u> e1	Base Plant	Mercu	ry <u>N</u> Ox Control	<u>T</u> S Con	SP SP ttrol Co	O2 ntrol	C <u>O</u> 2 Capture	By-Pr Mgi	od. nt Sta
			Title		Units	Unc	Value	Calc	Min	Max	Default
	1	Misc. Chemic	als Cost		\$/ton CO2		0.2600		0.0	10.00	0.2600
	2	Wastewater 7	Freatment Cost		\$/ton		0.0		0.0	30.00	0.0
	3	Electricity Pri	ice (Base Plant)		\$/MWh		40.47	Ľ	0.0	100.0	calc
	4										
	5	Number of Op	perating Jobs		jobs/shift		2.000		0.0	30.00	2.000
	6	Number of Op	perating Shifts		shifts/day		4.750		0.0	10.00	4.750
	7	Operating La	bor Rate		\$/hr		24.82		0.0	100.0	24.82
	8	Total Mainter	nance Cost		%TPC		4.000	<b>N</b>	0.0	10.00	calc
	9	Maint. Cost A	Allocated to Lab	or	% total		40.00		0.0	100.0	40.00
	10	Administrativ	7e & Support Co	st	% total labor		30.00		0.0	100.0	30.00
	11										
	12	CO2 Transp	ort and Storage	Costs							
	13	CO2 Transpo	rtation Cost		\$/ton-mile		2.362		0.0	0.1000	calc
	14	CO2 Storage	Cost		\$/ton		5.386		-150.0	60.00	calc
	15										
	16										
	17										
	18										

O2-CO2 Recycle Flue Gas – O&M cost input screen

Inputs for operation and maintenance are entered on the **O&M Cost** input. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below

- **Misc. Chemicals Cost:** This is the annual cost of chemicals that are used in the **Flue Gas Recycle** area of the plant. The cost is reported in dollars per ton of CO2 captured.
- Wastewater Treatment Cost: This is the annual cost of treating the wastewater that is used in the Flue Gas Recycle area of the plant. The cost is reported in dollars per ton.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)
- **Operating Labor Rate:** The number of dollars paid per hour to an operator for one hour of work.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- **Maint. Cost Allocated to Labor:** Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

#### CO₂ Transport and Storage Costs

- **CO₂ Transportation Cost:** Transportation of CO₂ product is assumed to take place via pipelines. This is the unit cost of CO₂ transport in \$/ton -mile.
- **CO₂ Storage Cost:** This is the unit cost of CO₂ disposal. Depending upon the method of CO₂ disposal or storage, either there may be some revenue generated (Enhanced Oil Recovery, Coal Bed Methane) which may be treated as a "negative cost", or additional cost (all other disposal methods).

# O₂-CO₂ Recycle Diagram



This screen is available for Combustion (Boiler) plant types.

O₂-CO₂ Recycle Flue Gas – Diagram.

#### **Recycled Flue Gas**

**Temperature:** The temperature of the **Recycled Flue Gas** from the direct contact cooler.

- Flue Gas Flow: The mass flow rate of the **Recycled Flue Gas** from the direct contact cooler.
- Fly Ash Flow: The mass flow rate of fly ash in the **Recycled Flue Gas** from the direct contact cooler.

#### **Direct Contact Cooler**

**Temperature In:** The temperature of the flue gas, to be recycled, entering the direct contact cooler.

- Flue Gas In: The mass flow rate of the flue gas, to be recycled, entering the direct contact cooler.
- Fly Ash In: The mass flow rate of fly ash in to the direct contact cooler.
- **Condensed Water:** The mass flow rate of condensed water leaving the direct contact cooler.

#### Released to Atmosphere

- **Temperature Out:** The temperature of the flue gas being released to the atmosphere.
- Flue Gas Out: The mass flow rate of the flue gas being released to the atmosphere.
- Fly Ash Out: The mass flow rate of the fly ash being released to the atmosphere.

#### Other

- Condensed Water: The mass flow rate of condensed water.
- **CO₂ Product Pressure:** This is the target pressure of product CO₂ being sent to storage.
- **CO₂ to Storage:** The mass flow rate of CO₂ being sent to storage.

# O₂-CO₂ Recycle DCC Gas Results

This screen is available for Combustion (Boiler) plant types.

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,	ſ		Configure Plant	Set <u>P</u> ara	meters	Ĩ	<u>G</u> et Re	sults
		Ove <u>r</u> ai Plant	Fuel Boiler Air Co	IOx ntrol Mercu	uy <u>T</u> SP Control	<u>S</u> O2 Control	C <u>O</u> 2 By Capture I	r-Prod. Mgmt Stac <u>k</u>
			Major Flue Gas Components	Flue Gas In (B-moles/hr)	Flue Gas Recycled (lb-moles/hr)	Flue Gas Out (B-moles/hr)	Flue Gas In (tons/hr)	Flue Gas Recycled (tons/hr)
		1	Nitrogen (N2)	6809	4766	2043	95.35	66.75
T		2	Oxygen (O2)	1514	1060	454.3	24.23	16.96
11		3	Water Vapor (H2O)	2.155e+04	3759	1611	194.1	33.87
411		4	Carbon Dioxide (CO2)	6.529e+04	4.570e+04	1.959e+04	1437	1006
		5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0
11		6	Hydrochloric Acid (HCl)	0.5750	0.4025	0.1725	1.048e-02	7.338e-03
		7	Sulfur Dioxide (SO2)	39.12	27.39	11.74	1.253	0.8771
비니		8	Sulfuric Acid (equivalent SO3)	0.3534	0.2474	0.1060	1.415e-02	9.902e-03
		9	Nitric Oxide (NO)	54.36	38.05	16.31	0.8156	0.5709
		10	Nitrogen Dioxide (NO2)	2.861	2.003	0.8583	6.582e-02	4.607e-02
		11	Ammonia (NH3)	0.0	0.0	0.0	0.0	0.0
		12	Argon (Ar)	3481	2437	1044	69.53	48.67
		13	Total	9.874e+04	5.779e+04	2.477e+04	1822	1173
		14						
		15 I Proc	ss Type: FG Recycle & Purification	<b>•</b>				Þ
		1.1	iagram <u>2. DCC Gas</u> <u>3</u> . Purif. Ga	s 🖌 <u>4</u> . Capita	1Cost / <u>5</u> .08	&M Cost 🖌 🧕	. TotalCost /	<u>7</u> . Misc. /

O₂-CO₂ Recycle Flue Gas – DCC Gas result screen.

#### **Major Flue Gas Components**

Each result is described briefly below:

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# O₂-CO₂ Recycle Purification Gas Results

		Configure Plant	Set <u>P</u> ara	meters	Ĩ	<u>G</u> et Re	sults
Ov P	7e <u>r</u> all 1ant	F <u>u</u> el <u>B</u> oiler <u>Air</u> Preheater C	<u>N</u> Ox <u>M</u> ercu	ary <u>T</u> SP Control	<u>S</u> O2 Control	C <u>O</u> 2 By Capture I	r-Prod. Mgmt Stac <u>i</u>
		Major Flue Gas Components	Flue Gas In (lb-moles/hr)	Flue Gas Captured (B-moles/hr)	Flue Gas Exhaust (D-moles/hr)	Flue Gas In (tons/hr)	Flue Gas Captured (tons/hr)
	1	Nitrogen (N2)	2043	150.7	1892	28.61	2.110
	2	Oxygen (O2)	454.3	150.7	303.7	7.269	2.411
	3	Water Vapor (H2O)	1611	0.0	11.08	14.51	0.0
	4	Carbon Dioxide (CO2)	1.959e+04	1.763e+04	1959	431.0	387.9
	5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0
	6	Hydrochloric Acid (HCl)	0.1725	0.0	0.1725	3.145e-03	0.0
	7	Sulfur Dioxide (SO2)	11.74	0.0	11.74	0.3759	0.0
	8	Sulfuric Acid (equivalent SO3)	0.1060	0.0	0.1060	4.244e-03	0.0
	9	Nitric Oxide (NO)	16.31	0.0	16.31	0.2447	0.0
	10	Nitrogen Dioxide (NO2)	0.8583	0.0	0.8583	1.974e-02	0.0
	11	Ammonia (NH3)	0.0	0.0	0.0	0.0	0.0
	12	Argon (Ar)	1044	150.7	893.6	20.86	3.010
	13	Total	2.477e+04	1.808e+04	5088	502.9	395.5
	14						
	15						
	<u> </u>	<b>.</b>					<u>•</u>

This screen is available for Combustion (Boiler) plant types.

O₂-CO₂ Recycle Flue Gas – Purif. gas result screen.

#### **Major Flue Gas Components**

Each result is described briefly below:

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCI): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# O₂-CO₂ Recycle Capital Cost Results

This screen is available for Combustion (Boiler) plant types.

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ы	5-	Unti	led*				
			<u>C</u> onfigure Plant	Set <u>P</u> a	ame	ters Get Re	esults
		Ove <u>r</u> Plar	all t Fuel <u>B</u> oiler <u>A</u> ir Preheater	NOx Control Mer	cury	TSP     SO2     CO2     B1       Control     Control     Capture     I	g-Prod. Mgmt Stac <u>k</u>
*			Flue Gas Recycle Process Area Costs	Capital Cost (M\$)		Flue Gas Recycle Plant Costs	Capital Cost (M\$)
E.	Ш	1	Boiler Modifications	0.0	1	Process Facilities Capital	71.92
ref.	Ш	2	Flue Gas Recycle Fan	1.776	2	General Facilities Capital	7.192
	Ш	3	Flue Gas Recycle Ducts	8.773	3	Eng. & Home Office Fees	5.034
	Ш	4	Oxygen Heater	14.25	4	Project Contingency Cost	10.79
	Ш	5	CO2 Purification System	6.204	5	Process Contingency Cost	3.596
2	Ш	6	Direct Contact Cooler	19.72	6	Interest Charges (AFUDC)	7.741
2	Ш	7	CO2 Compression System	21.19	7	Royalty Fees	0.3596
<u>~</u>	Ш	8	Process Facilities Capital	71.92	8	Preproduction (Startup) Cost	5.516
	Ш	9			9	Inventory (Working) Capital	0.4927
	Ш	10			10	Total Capital Requirement (TCR)	112.6
	Ш	11			11		
	Ш	12			12		
	Ш	13			13		
	Ш	14			14		
	Ш	15			15	Effective TCR	112.6
		Pro	cess Type: FG Recycle & Purificatio	n 💌		Costs are in Constant 2005 dollars.	
		1	. Diagram 🖌 2. DCC Gas 🖌 3. Purif.	Gas <u>4</u> Capi	ital Co	st 🖌 <u>5</u> . O&M Cost 🖌 <u>6</u> . Total Cost 🖌	7. Misc.

O2-CO2 Recycle Flue Gas – Capital cost result screen.

The **Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

#### Flue Gas Recycle Process Area Costs

**Boiler Modifications:** In case of a *pre-existing* PC plant being retrofitted for  $CO_2$  capture, the boiler must be modified to suit the new oxyfuel combustion system. The cost for these modifications is estimated as a percentage of the cost of the boiler

**Flue Gas Recycle Fan:** The cost of the fan required for recycling part of the flue gas is scaled on the basis of the flow rate of the flue gas being recycled

- **Flue Gas Recycle Ducts:** Additional ducting is necessary to recycle part of the flue gas in the oxyfuel combustion system. The cost of this ducting is assumed to be a function of the flow rate of recycled flue gas.
- **Oxygen Heater:** In addition to the air preheater that exists in a conventional PC plant, the oxyfuel combustion system includes an additional heat exchanger called the "oxygen heater" for better heat integration. The cost of this heat exchanger is scaled on the basis of the gross plant size
- **CO₂ Purification System:** The cost of the CO₂ purification system depends on the desired purity level of the CO₂ product, and the total CO₂ product flow rate.
- **Direct Contact Cooler:** The cost of the flue gas cooler is scaled on the basis of the flow rate of the flue gas.
- $CO_2$  Compression System: The multi-stage compression unit with inter-stage cooling and drying yields the final CO₂ product at the specified pressure (about 2000 psig) that contains only acceptable levels of moisture and other impurities (e.g. N₂) The size (and cost) of this unit will be a function of the CO₂ product compression power.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

#### Flue Gas Recycle Plant Costs

- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.
- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

# O₂-CO₂ Recycle O&M Cost Results

This screen is available for Combustion (Boiler) plant types.

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6	ľ		Configure Plant	Set <u>P</u> a	ame	ters	<u>G</u> et	Results
		Ove; Plai	all Fuel Boiler Air nt Fuel Boiler Preheater	NOx Control Mer	cury	TSP Control Co	02 ntrol C <u>O</u> 2 Capture	By-Prod. Mgmt Stac <u>k</u>
*			Variable Cost Conponent	O&M Cost (M\$/yr)		Fixed C	ost Component	O&M Cost (M\$/yr)
G.		1	Misc. Chemicals	0.6568	1	Operating Labor		0.6025
		2	Wastewater Treatment	0.0	2	Maintenance Lab	or	1.576
		3	CO2 Transport	6.083	3	Maintenance Ma	terial	2.365
		4	CO2 Storage	13.87	4	Admin. & Suppo	rt Labor	0.6537
		5	Electricity	14.88	5	Total Fixed Costs		5.197
?		6	Total Variable Costs	35.49	6			
N?		7			7			
-		8			8			
		9			9			
		10			10			
		11			12			
		13			13			
		14			14			
		15			15	Total O&M Cost	s	40.69
		Pro	cess Type: FG Recycle & Purificatio	• •		Costs are in (	Constant 2005 dollar	rs.
			. Diagram 🖌 2. DCC Gas 🔏 3. Purif.	.Gas 🖌 <u>4</u> .Capi	tal Co	st 🔪 <u>5</u> . O&M Co	st <u>6</u> . Total Cos	t / 7. Misc. /

 $O_2$ - $CO_2$  Recycle Flue Gas – O&M cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **CO2 Capture** technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

#### **Variable Cost Components**

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

- **Misc. Chemicals:** A small quantity of chemicals is used in this process, including chemicals, desiccant and lubricants. The aggregate cost of these chemicals is estimated based on the flow rate of CO₂ captured
- **Wastewater Treatment:** The user may enter a cost for treating the moisture condensed from the flue gas.
- $CO_2$  Transport: The CO₂ captured at the power plant site has to be carried to the appropriate storage/ disposal site. Transport of CO₂ to a storage site is assumed to be via pipeline This is the annual cost of maintaining those pipelines.
- **CO₂ Storage:** Once the CO₂ is captured, it needs to be securely stored (sequestered). This cost is based upon the storage option chosen on the  $O_2$ -CO₂ Recycle Flue Gas CO₂ storage input screen.
- **Electricity:** The cost of electricity consumed by the **Flue Gas Recycle** System.

**Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

#### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

# O₂-CO₂ Recycle Total Cost Results

This screen is available for Combustion (Boiler) plant types.

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		<u>(</u>	<u>]</u> on	figure Plant	Sei	t <u>P</u> arametei	s	<u>(</u>	et Results	
	0	Overall Plant	F	uel <u>B</u> oiler A Preh	<u>i</u> r <u>N</u> Ox eater Control	Mercury	TSP Sontrol Con	02 ntrol C <u>O</u> 2 Captu	re By-Prod. Mgmt	Stac <u>k</u>
				Cost Compo	onent	M\$/yr	\$/MWh	\$/ton CO2 transported	Percent Total	
I			1	Annual Fixed Cost		5.197	2.361	2.057	9.061	
			2	Annual Variable Cost		35.49	16.12	14.05	61.88	
			3	Total Annual O&M Cost	t	40.69	18.48	16.11	70.94	
			4	Annualized Capital Cost	Cost	57.36	26.06	0.599	29.06	
			6	1 oral 2010 and 0 Thinks of		01.00	20.00		100.0	
			7							
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			9							
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			11							
			12							
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			14							
		Process	Туре	FG Recycle & Puri	ification 💌	1	Costs are in C	onstant 2005 d	ollars.	
		<u>1</u> . Diag	gram	2. DCC Gas	3. Purif. Gas 🖌 🖉	. Capital Cost	<u>5</u> .0&MCo:	st 🛕 <u>6</u> . Total	Cost <u>7</u> . N	lisc.

*O*₂-*CO*₂ *Recycle Flue Gas* – *Total cost result screen.* 

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Flue Gas Recycle** portion of the **CO2 Control** technology. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

#### **Cost Component**

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

### O₂-CO₂ Recycle Miscellaneous Results

This screen is available for Combustion (Boiler) plant types.

ile [	CM <u>E</u> di	Inter it ⊻i∈	fa <b>ce</b> w Go <u>W</u> indow <u>H</u> elp				
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5			<u>C</u> onfigure Plant	Set <u>P</u> ar	ame	ters <u>G</u> et Re	sults
		Ove; Pla	all _t F <u>u</u> el <u>B</u> oiler <u>A</u> ir Preheater I	<u>N</u> Ox Control <u>M</u> er	cury	<u>TSP</u> SO2CO2 Control Control Capture I	r-Prod. Mgmt Stac <u>k</u>
			Important Performance and Cost Factors	Value		Cost of CO2 Avoided	Value
1	Ш	1	Net Plant Size (MW)	334.5	1	Capture Plant	
ат III	Ш	2	Annual Operating Hours (hours)	6575	2	CO2 Emissions (Ibs/kWh)	0.2577
	Ш	3	Annual CO2 Removed (tons/yr)	2.550e+06	3	Cost of Electricity (\$/MWh)	100.5
	Ш	4			4		
2II	Ш	5	ASU Energy (MW)	77.40	5	Reference Plant	
1	Ш	6			6	CO2 Emissions (lbs/kWh)	0.0
,	Ш	7	Flue Gas Fan Energy (MW)	0.2393	7	Cost of Electricity (\$/MWh)	0.0
-	Ш	8	Flue Gas Cooling Energy (MW)	4.334	8		
	Ш	9	CO2 Purification Energy (MW)	6.983	9	Cost of CO2 Avoided (\$/ton)	0.0
	Ш	10	CO2 Compression Energy (MW)	41.51	10		
	Ш	11	Total Recycle/Purification Energy (MW)	53.06	11		
	Ш	12			12		
	Ш	13			13		
	Ш	14	Fixed Charge Factor (fraction)	0.1480	14		
	Ш	15			15		
		Pro	cess Type: FG Recycle & Purification	T		Costs are in Constant 2003 dollars.	
			Diagram <u>2. DCC Gas</u> <u>3. Purif. (</u>	∃as <u>∕4</u> .Capi	tal Co	st 🖌 <u>5</u> . O&M Cost 🖌 <u>6</u> . TotalCost )	<u>7</u> . Misc.

*O*₂-*CO*₂ *Recycle Flue Gas – Miscellaneous factor result screen.* 

The **Misc.** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Flue Gas Recycle** portion of the **CO₂ Control** technology. Each result is described briefly below.

#### **Important Performance and Cost Factors**

This screen displays information that is key to the model calculations. The data is available else where in the model.

- **Net Plant Size (MW):** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).
- Annual Operating Hours (hours): This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.
- Annual  $CO_2$  Removed (ton/yr): This is the amount of  $CO_2$  removed from the flue gas by the  $CO_2$  capture system per year.

#### ASU Power (MW)

Flue Gas Fan Power (MW): The flue gas has to be compressed in a flue gas blower so that it can overcome the pressure drop in the absorber tower. This is the electrical power required by the blower.

#### CO₂ Purification Power (MW)

 $CO_2$  Compression Power (MW): This is the electrical power required to compress the CO₂ product stream to the designated pressure. Compression of CO₂ to high pressures requires considerable power, and is a principle contributor to the overall energy penalty of a CO₂ capture unit in a power plant. **Fixed Charge Factor (fraction):** The fixed charge factor is one of the most important parameters in the IECM. It determines the revenue required to finance the power plant based on the capital expenditures. Put another way, it is a levelized factor which accounts for the revenue per dollar of total plant cost that must be collected from customers in order to pay the carrying charges on that capital investment.

#### Cost of CO₂ Avoided

Many analysts like to express the cost of an environmental control system in terms of the cost per ton of pollutant removed or avoided. For energy-intensive  $CO_2$  controls there is a big difference between the cost per ton  $CO_2$  removed and the cost per ton "avoided" based on *net* plant capacity. Since the purpose of adding a  $CO_2$  unit is to reduce the  $CO_2$  emissions per net kWh delivered, the cost of  $CO_2$  avoidance is the economic indicator that is widely used in this field.

#### **Capture Plant**

- **CO₂ Emissions (lb/kWh):** This is the amount of CO₂ vented to the air for every kilowatt hour of electricity produced in the power plant that is using **CO₂ Capture Technology**.
- **Cost of Electricity (\$/MWh):**The IECM framework calculates the cost of electricity (COE) for the overall **Capture Plant** by dividing the total annualized plant cost (\$/yr) by the net electricity generated (kWh/yr)

#### **Reference Plant**

- **CO₂ Emissions (lb/kWh):** This is the amount of CO₂ vented to the air for every kilowatt hour of electricity produced in the power plant with **No CO₂ Capture**.
- **Cost of Electricity (\$/MWh):** The IECM framework calculates the cost of electricity (COE) for the overall **Reference Plant** by dividing the total annualized plant cost (\$/yr) by the net electricity generated (kWh/yr)
- **Cost of CO₂ Avoided (\$/ton):** This is the economic indicator widely used in the field, calculated as the difference between the cost of electricity in the capture plant and the reference plant divided by the difference between the  $CO_2$  emissions in the reference plant and the capture plant.

Cost of CO₂ Avoided = (Cost of Electricity _{cap.} – Cost of Electricity _{ref.})

/ (CO₂ emissions  $_{ref.}$  – CO₂ emissions  $_{cap.)}$ 

# Selexol CO₂ Capture

IGCC systems use less energy-intensive physical absorption processes to capture  $CO_2$  than post-combustion chemical absorption processes required by the **Combustion (Boiler)** or **Combustion (Turbine)** plant types. Physical absorption using Selexol solvent is currently the most effective technique for removing  $CO_2$  from IGCC fuel gases. The  $CO_2$  capture using Selexol is described in the following section.

### Selexol CO₂ Capture Reference Plant Inputs

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	Overall Plant Fuel <u>A</u> ir Separation	Gasifie <u>r</u> <u>S</u> Area Re	ulfur moval	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. <u>M</u> gmt	Stac <u>k</u>
6	Title	Units	Unc	Value	Calc Min	Max I	Default
¥	Reference Plant Inputs for Avoided Cost Calculation						
	3 Reference Plant						
	4 CO2 Emission Rate	lbs/kWh		1.704	0.0	5.000	calc
đ	5 Cost of Electricity	\$/MWh		49.50	<b>1</b> 0.0	150.0	calc
?	6 7						
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	<u>1. Reference Plant</u> <u>2. Performance</u>	3. CO2 Storage	4. R	etrofit Cost	<u>5</u> . Capital C	ost <u>6</u> .0	)&M Cost /

This screen is only available for the **IGCC** plant type.

Selexol CO₂ Capture – Reference Plant input screen.

### **Reference Plant**

**CO₂ Emission Rate:** This is the emission rate for the reference power plant (without CO₂ capture).

**Cost of Electricity:** This is the cost of electricity for the reference power plant (without CO₂ capture).

# **Selexol CO₂ Capture Performance Inputs**

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	Overall Plant Fuel Air Separation	Gasifier <u>S</u> ul Area Rem	lur oval	C <u>O</u> 2 Capture	Po	wer <u>B</u> lock	By-Prod Mgmt	. Stac <u>k</u>	
	Title	Units	Unc	Value	Calc	Min	Max	Default	
	1 Carbon Dioxide Removal Unit								
111	2 CO2 Removal Efficiency	%		95.00	Ľ	50.00	98.00	calc	
111	3 H2S Removal Efficiency	%		94.00		0.0	100.0	94.00	
ill	4 5 May Syngas Canacity ner Train	lh-mole/hr		3 200 0 +04		0.0	3 500e+04	3 200e+04	
11	6 Number of Operating Absorbers	integer	_	2	1	Menu	Menu	calc	
111	7 Number of Spare Absorbers	integer	_	0 -	_	Menu	Menu	0	
Ш	8	8		· _					
	9 Power Requirement	% MWg		7.446	V	0.0	15.00	calc	
	10								
11	11								
Ш	12								
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	10		-						
	17		-						
	Process Type: 2. Selexol CO2 Ca	pture 💌	1	<u> </u>		1	1		
	1. Reference Plant 2. Performance	<u>3</u> . CO2 Storage /	<u>4</u> . F	Retrofit Cost	Κ.	<u>5</u> . Capital C	ost / <u>6</u>	<u>í</u> . O&M Cost	Ź

This screen is only available for the **IGCC** plant type.

Selexol CO₂ Capture – Performance input screen.

### **Carbon Dioxide Removal Unit**

- **CO₂ Removal Efficiency:** CO₂ removal is specified by the user and is used to determine the solvent makeup flow, capital cost, and operating and maintenance costs.
- **H₂S Removal Efficiency:** H₂S is naturally removed with CO₂. This parameter specifies the amount it is captured.
- **Max Syngas Capacity per Train:** Each train contains one absorber vessel that has a maximum flow rate. This parameter determines the maximum flow rate through the vessel.
- **Number of Operating Absorbers:** This is the total number of operating absorber vessels. The calculated value is determined by comparing the total flow rate of syngas through the Selexol process and the maximum syngas capacity per train. The value must be an integer.
- **Number of Spare Absorbers:** This is the total number of spare absorber vessels. It is used primarily to calculate capital costs. The value must be an integer.
- **Power Requirement:** This is the electricity used by the **Selexol CO2 Capture System** for internal use. It is expressed as a percent of the gross plant capacity.

# Selexol CO₂ Capture CO₂ Storage Inputs

This screen is only available for the **IGCC** plant type.

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9				Ti	tle		Uni	ts	Unc		Value	Cal	c Mi	in	Max	Default	
*	Ш	1		CO2 Produ	uct Stream												
	Ш	2	1	Jumber of Compr	essors		integ	ger		3	-		Me	nu	Menu	3	
	Ш	3	F	Product Pressure			psi	g			2000		0.	.0	4000	2000	
	Ш	4	0	CO2 Compressor I	Efficiency		%				80.00		0.	0	100.0	80.00	
	Ш	5															
	Ш	6		<u>Transport</u>	& Storage												
	Ш	7	2	Storage Method:						G	eologic		Me	nu	Menu	Geologic	
	Ш	8				_			_				_				
<u>*</u>	Ш	9	1	Inhanced Oil Rea	covery (EOR)	_											
<u></u>	Ш	10	) /	Enhanced Coal E	led Methane (E.	•						_					
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	Ш	14	+ =			+				-		-					
	Ш	14	5			+			-	-		-	-				
	Ш	12	7			+			-	-		-					
	11	17	2			+			+	-		-	+				
		Pro	oce:	ss Type: 2. Se	lexol CO2 Ca	ptur	e	•									
		<u>1</u> . Refe	ren	ice Plant 🖌 🧕 P	erformance	3.	CO2 Sto	rage /	<u>4</u> . F	Reta	rofit Cost	K	<u>5</u> . Capi	ital Co	ost 🧹 🤉	<u>6</u> . O&M Co	st

Selexol CO₂ Capture – CO₂ Storage input screen.

### CO₂ Product Stream

The concentrated  $CO_2$  product stream obtained from  $CO_2$  capture technology is compressed and dried using a multi-stage compressor with inter-stage cooling.

- **Number of Compressors:** The number of compressors is a userspecified number. The value is used to determine the capital cost for sequestration.
- **Product Pressure:** The  $CO_2$  product may have to be carried over long distances. Hence, it is necessary to compress (and liquefy) it to very high pressures, so that it may be delivered to the required destination in liquid form and (as far as possible) without recompression facilities en route. The critical pressure for  $CO_2$  is about 1070 psig.
- $CO_2$  Compressor Efficiency: This is the effective efficiency of the compressors used to compress  $CO_2$  to the desired pressure.

### **Transport & Storage**

**Storage Method:** The default option for CO₂ disposal is underground geological storage.

- **EOR** Enhanced Oil Recovery
- **ECBM** Enhanced Coal Bed Methane
- **Geologic** Geological Reservoir
- Ocean

# Selexol CO₂ Capture Retrofit Cost Inputs

This screen is only available for the **IGCC** plant type.

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	Overall Plant Fuel Air Separation	Gasifier Su Area Ren	lfur ioval	C <u>O</u> 2 Capture	Por	ver <u>B</u> lock	By-Prod Mgmt	I. Stac <u>k</u>
l	Title	Units	Unc	Value	Calc	Min	Max	Default
I	1 Capital Cost Process Area							
I	2 Absorbers	retro \$/new \$		1.000		0.0	10.00	1.000
I	3 Power Recovery Turbines	retro \$/new \$		1.000		0.0	10.00	1.000
I	4 Slump Tanks	retro \$/new \$		1.000		0.0	10.00	1.000
l	5 Recycle Compressors	retro \$/new \$		1.000		0.0	10.00	1.000
l	6 Flash Tanks	retro \$/new \$		1.000		0.0	10.00	1.000
l	7 Selexol Pumps	retro \$/new \$		1.000		0.0	10.00	1.000
I	8 Refrigeration	retro \$/new \$		1.000		0.0	10.00	1.000
I	9 CO2 Compressors	retro \$/new \$		1.000		0.0	10.00	1.000
l	10 Final Product Compressors	retro \$/new \$		1.000		0.0	10.00	1.000
l	11 Heat Exchangers	retro \$/new \$		1.000		0.0	10.00	1.000
l	12							
l	13							
I	14							
l	15							
I	16							
I	17							
I	18							
	Process Type: 2. Selexol CO2 Ca	pture 💌						·
l	1. Reference Plant / 2. Performance /	<u>3</u> . CO2 Storage	<u>4</u> .R	etrofit Cost	5	. Capital Co	ost 🖉 !	<u>6</u> .0&MCost /

Selexol CO₂ Capture – Retrofit Cost input screen.

### **Capital Cost Process Area**

The retrofit ratios can be specified for the following process areas:

- **Absorbers:** The Selexol absorbers use physical absorption to capture  $CO_2$ . Because the solubility of  $CO_2$  in the solvent is proportional to its partial pressure in the gas phase, the performance of the absorbers increases with increasing  $CO_2$  partial pressures.
- **Power Recovery Turbines:** The  $CO_2$  rich solvent from the absorber is fed into a set of hydraulic power recovery turbines to recover some of the pressure energy before it is fed into the slump tanks.
- **Slump Tanks:** A slight pressure drop in the slump tanks releases a majority of  $H_2$  and  $CH_4$  and a small amount of  $CO_2$ . This process area enriches the  $CO_2$  concentration.
- **Recycle Compressors:** Gases from the slump tank are recycled back into the absorber. A compressor is used to compress the gases to the operating pressure of the absorber.
- **Flash Tanks:**  $CO_2$  is released in multiple stages by reducing the pressure in successive flash tanks. Three flash tanks are typically used in a single train. The staging process reduces the power of  $CO_2$  compression later.
- **Selexol Pumps:** The CO₂-lean solvent is pumped back to the absorber operating pressure by a Selexol circulation pump.
- **Refrigeration:** CO₂-lean solvent must be cooled to the absorber operating temperature before being returned to the absorber vessel. A refrigeration unit is used to reduce the temperature of the solvent.
- $CO_2$  Compressors:  $CO_2$  released from the first two flash tanks is compressed to the flashing pressure of the first flash tank. The two  $CO_2$ streams are then combined and sent to the final product compressors.

- **Final Product Compressors:** The product  $CO_2$  must be separated from the water vapor (dried) and compressed to liquid form in order to transport it over long distances. The multi-stage compression unit with inter-stage cooling and drying yields a final  $CO_2$  product at the nominal pressure of 2000 psig. This area is a function of the  $CO_2$  flow rate.
- **Heat Exchangers:** This process area considers miscellaneous heat exchangers used in the overall process.

### Selexol CO₂ Capture Capital Cost Inputs

This screen is only available for the IGCC plant type.

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		Ove <u>r</u> all :	P1aı	nt F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ul Rem	fur oval	C <u>O</u> 2 Capture	Po	wer <u>B</u> lock	By-Prod Mgmt	I. St	ac <u>k</u>
9		Г		Ti	itle	Uni	ts	Unc	Value	Calc	Min	Max	Default	
*		Ē	1	Construction Tim	e	yea	rs		4.000		0.2500	10.00	4.000	
Ba		-	2											
			3	General Facilities	Capital	%PI	FC .		15.00		0.0	50.00	15.00	
			4	Engineering & Ho	ome Office Fees	%PI	FC		10.00		0.0	50.00	10.00	
œ'			5	Project Continger	ncy Cost	%PI	FC .		15.00		0.0	100.0	15.00	
			6	Process Continge	ncy Cost	%PI	FC .		10.00		0.0	100.0	10.00	
÷.			7	Royalty Fees		%PI	FC		0.5000		0.0	10.00	0.5000	
믐			8											
8			9	Pre-Produ	ction Costs									
<b>\?</b>		1	10	Months of Fixed (	O&M	mon	ths		1.000		0.0	12.00	1.000	
		1	11	Months of Variab	le O&M	mon	ths		1.000		0.0	12.00	1.000	
		1	12	Misc. Capital Cos	t	%T	PI		2.000		0.0	10.00	2.000	
		1	13											
		1	14	Inventory Capital		%T	PC		0.5000		0.0	10.00	0.5000	
			15											
		1	16											
		1	17											
			18	TCR Recovery Fa	ictor	%			100.0		0.0	200.0	100.0	
		Pı	roc	ess Type: 2. Se	elexol CO2 Cap	ture	•							
		<u>1</u> . Rei	fere	nce Plant 🖌 🙎 F	Performance	<u>3</u> . CO2 Sto	rage /	<4. R	etrofit Cost	<u>λ</u> :	. Capital Co	ost	<u>6</u> . O&M Co	st

Selexol CO₂ Capture – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

**Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

- **General Facilities Capital (GFC)**: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-

by-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during startup. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.
  - **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
  - **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
  - **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

### Selexol CO₂ Capture O&M Cost Inputs

This screen is only available for the **IGCC** plant type.

	Configure Plant	Ĩ	Se	t Para	mete	rs	Ĩ		Get Res	ults	
Overall Plant Fuel Air Separation		ir ration	Gasifier Area	<u>S</u> ulf Remo	iur oval	C <u>O</u> 2 Capture	C <u>O</u> 2 Capture Power <u>B</u> lock			By-Prod. Mgmt Stack	
	Title		Unit	5	Unc	Value	Calc	Min	Max	Default	
1	Bulk Reagent Storage Ti	me	days	;		60.00		0.0	120.0	60.00	
2											
3	Glycol Cost		\$/1b			2.356	M	0.0	10.00	calc	
4	Waste Disposal Cost		\$/to:	ı		0.0	Ľ	0.0	30.00	calc	
5	Electricity Price (Base Pl	ant)	\$/MV	7h		61.06	Ľ	0.0	200.0	calc	
6											
7	Number of Operating Jo	os	jobs/sl	uift		2.000		0.0	30.00	2.000	
8	Number of Operating Sh	ifts	shifts/day			4.750	0.0	10.00	4.750		
9	Operating Labor Rate		\$/hr			24.82		0.0	100.0	24.82	
10				-							
11	Total Maintenance Cost	• •	%TP			5.000		0.0	10.00	calc	
12	Maint. Cost Allocated to	Labor	% tot	al		40.00		0.0	100.0	40.00	
13	A aministrative & Suppo	rtCost	% total l	abor		30.00		0.0	100.0	30.00	
14	Transport and Stores	o Coata									
15	CO2 Transport and Storag	te Costs	\$/101			2.099		0.0	10.00	cale	
10	CO2 Mansportation Cost	ı	\$/101	-		5.452		-150.0	00.00	calc	
17	CO2 Diolage Cost		4/101	1		J.4JZ		-130.0	00.00	carc	
18				_							

Selexol CO₂ Capture – O&M Cost input screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. The following inputs for operating and maintenance costs are available:

Bulk Reagent Storage Time: This is the reagent stored at the plant.

- **Glycol Cost:** This is the cost in \$/ton for glycol that is used by the Selexol CO₂ capture system.
- **Waste Disposal Cost:** This is the cost of disposing the water that is used in the Selexol CO₂ capture process.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is an air separation unit, gasifier and the power block
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

#### **Transport and Storage Costs**

- **CO₂ Transportation Cost:** This is the cost of moving the CO₂ (i.e. pipeline, truck) to the place where it will be sequestered.
- **CO₂ Disposal Cost:** This is the cost of sequestering the CO₂.

# Selexol CO₂ Capture Diagram

This screen is only available for the **IGCC** plant type.



Selexol CO₂ Capture – Diagram result screen.

The **Selexol CO₂ Capture Diagram** result screen displays an icon for the Selexol  $CO_2$  capture unit and values for major flows in and out of it. Each result is described briefly below:

**Temperature In:** Temperature of the syngas entering the CO₂ absorber unit.

Syngas In: Flow rate of the syngas entering the CO₂ absorber unit.

**Solvent Makeup:** Flow rate of the Selexol solvent added to the regenerator.

**Temperature Out:** Temperature of the syngas exiting the CO₂ absorber unit.

Syngas Out: Flow rate of the syngas exiting the CO₂ absorber unit.

**CO₂ Product:** Flow rate of the CO₂ product exiting the regenerator.

**CO₂ Syngas Pressure:** CO₂ product pressure entering the pipeline.

# Selexol CO₂ Capture Syngas Results

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	Ove <u>r</u> all Plant	F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stack
		Ν	lajor Syngas Con	<b>ponents</b>	Syngas In (Ib-moles/hr)	Syngas Out (lb-moles/hr)	Syngas In (ton/hr)	Syngas Out (ton/hr)	
	1	Carbon N	Ionoxide (CO)		918.4	918.4	12.86	12.86	
	2	Hydroge	n (H2)		3.177e+04	3.177e+04	32.09	32.09	
	3	Methane	(CH4)		135.2	135.2	1.084	1.084	
	4	Ethane (	C2H6)		0.0	0.0	0.0	0.0	
	£	7 Propane	(C3H8)		0.0	0.0	0.0	0.0	
	Ć	i Hydroge	n Sulfide (H2S)		0.2785	0.2785	4.746e-03	4.746e-03	
	7	Carbony	Sulfide (COS)		9.484	9.484	0.2848	0.2848	
	8	Ammoni	a (NH3)		3.196	3.196	2.722e-02	2.722e-02	
	9	Hydroch	loric Acid (HCI)		0.0	0.0	0.0	0.0	
	1	0 Carbon I	)ioxide (CO2)		2.243e+04	2243	493.7	49.37	
	1	1 Water Va	apor (H2O)		6639	6639	59.82	59.82	
1	1	2 Nitrogen	(N2)		352.5	352.5	4.937	4.937	
1	1	3 Argon (A	(t)		417.3	417.3	8.336	8.336	
1	1	4 Oxygen (	02)		0.0	0.0	0.0	0.0	
	1	5 Total			6.268e+04	4.249e+04	613.1	168.8	

This screen is only available for the IGCC plant type.

Selexol CO₂ Capture – Gas Flow result screen..

### **Major Syngas Components**

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H₂):Total mass of hydrogen.

Methane (CH₄): Total mass of methane.

Ethane (C₂H₆): Total mass of ethane.

Propane (C₃H₈): Total mass of propane.

Hydrogen Sulfide (H₂S):Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH₃): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Water Vapor (H₂O): Total mass of water vapor.

Nitrogen (N₂): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O₂): Total mass of oxygen.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.
## Selexol CO₂ Capture Capital Cost Results

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		Sele	xol (CO2) Pr	ocess Area Cos	ts	Capital Co (M\$)	st		Selexol	(CO2) Plant Cos	sts	Capital Cost (M\$)
I	1	Absorb	ers			14.92		1	Process Facilitie	s Capital		48.53
I	2	Power F	ecovery Turk	oines		2.395		2	General Facilitie	s Capital		7.280
I	3	Slump T	anks			1.177		3	Eng. & Home Of	fice Fees		4.853
I	4	Recycle	Compressors	,		3.467		4	Project Conting	ency Cost		7.280
I	5	Flash T	anks			2.581		5	Process Conting	gency Cost		4.853
I	6	Selexol I	Pumps			2.340		6	Interest Charge:	(AFUDC)		12.04
I	7	Refriger	ation			4.250		7	Royalty Fees			0.2427
I	8	CO2 Co	mpressors			11.95		8	Preproduction (	Startup) Cost		5.327
I	9	Final Pr	oduct Compre	ssors		1.756		9	Inventory (Wor	king) Capital		0.3640
I	10	Heat Ex	changers			3.702		10	Total Capital Re	quirement (TCR)	l i	90.77
I	11	Process	Facilities Cap	oital		48.53		11				
I	12							12				
I	13							13				
I	14							14				
l	15							15	Effective TCR			90.77
I	n								<i>a</i>			

This screen is only available for the IGCC plant type.

Selexol CO₂ Capture Capital Cost results screen.

The **Selexol CO₂ Capture Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

#### Selexol (CO₂) Capture Process Area Costs

- **Absorbers:** This is the series of columns where the syngas is made to contact with the Selexol solvent. Some of the  $CO_2$  is absorbed by the  $CO_2$  lean solvent at high pressure in the counter flow absorber. This process area PFC is a function of the solvent flow rate, the capture  $CO_2$  flow rate, and the inlet temperature.
- **Power Recovery Turbines:** The pressure energy in the  $CO_2$  rich solvent is recovered with one or two hydro turbines. This process area PFC is a function of the turbine horsepower and the turbine outlet pressure.
- **Slump Tanks:**  $H_2$ , CO, and  $CH_4$  entrained or absorbed in the solvent is released in the slump tank and recycled back to the absorber. Because extra Selexol is used in the absorber, only a small amount of  $CO_2$  is released in the slump tank. This process area PFC is a function of the solvent flow rate.
- **Recycle Compressors:** The lean solvent is compressed and cooled in preparation for recycling back into the absorbers. This process area PFC is a function of the compressor horse power.
- **Flash Tanks:** Most of the  $CO_2$  absorbed by the solvent is recovered through flashing. The captured  $CO_2$  is then ready for transport and sequestration. To reduce the compression power, three flashing tanks with different pressures are used. There is no heat demand for solvent

regeneration because solvent recovery is possible through flashing. This process area PFC is a function of the solvent flow rate.

- **Selexol Pumps:** The lean solvent fed back into the absorber via pumps. This process area PFC is a function of the pump horse power.
- **Refrigeration:** The solvent must be cooled down to the absorber operating temperature (30 °F) by refrigeration. This process PFC is a function of the solvent flow rate and the temperature difference.

 $CO_2$  Compressors: The CO₂ from the flash tanks is compressed to high pressure (>1000psia) for storage using a multi-stage, inter-stage cooling compressor. This process area PFC is a function of the compressor horse power.

- **Final Product Compressors:** Compressed  $CO_2$  from the  $CO_2$  compressors must be further compressed to the final product pressure. This process area PFC is a function of the compressor horse power.
- **Heat Exchangers:** Gas-gas heat exchangers are used to extract heat from the syngas. This process PFC is a function of the heat load of the exchangers and the temperature difference across them.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

#### Selexol (CO₂) Capture Plant Costs

Process Facilities Capital: (see definition above)

- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

# Selexol CO₂ Capture O&M Cost Results

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				Variable Cos	t Component		O&M (M\$/	Cost yr)		Fixed C	Cost Componen	t	O&M Cost (M\$/yr)	
E.		1	Glycol				0.0	)	1	Operating Labor			0.6025	
		2	Dispos	ાથા			0.0	)	2	Maintenance Lab	or		1.456	
		3	Electric	ity			16.7	74	3	Maintenance Ma	terial		2.184	
		4	CO2 Tr	ransport			6.08	32	4	Admin. & Suppo	rt Labor		0.6176	
		5	CO2 St	orage			15.8	38	5	Total Fixed Costs			4.860	
8		6	Total V	ariable Costs			38.7	70	6					
N?		7							7					
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		Pro	cess Ty	npe: 2. Sele	xol CO2 Cap	ture	Ţ	]		Costs are in (	Constant 2005	dollars.		
			<u>1</u> . Diag	ram 🖌	2. Syngas	<u></u>	Capital (	Cost	<u>\</u>	. O&M Cost	<u>5</u> . Total Cos	t <u>∕ 6</u> .0	Cost Factors	

This screen is only available for the **IGCC** plant type.

Selexol CO₂ Capture – O&M Cost results screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

#### Variable Cost Component

- **Glycol:** Selexol is a commercially available physical solvent that is a mixture of dimethyl ether and polyethylene glycol. This is the annual cost of the makeup solvent.
- **Disposal:** This is the annual cost of waste disposal for this process. It does not include the  $CO_2$  product stream disposal cost.
- **Electricity:** The cost of electricity consumed by the CO₂ Selexol system.
- **CO₂ Transport:** The CO₂ captured at the power plant site has to be carried to the appropriate storage/disposal site. Transport of CO₂ to a storage

site is assumed to be via pipeline. This is the annual cost of maintaining those pipelines.

- **CO₂ Storage/Disposal:** Once the CO₂ is captured, it needs to be securely stored (sequestered). This annual cost is based upon the storage option chosen.
- **Total Variable Costs:** This is the sum of the variable O&M costs listed above. This result is highlighted in yellow.

#### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- **Admin. & Support Labor:** The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

# Selexol CO₂ Capture Total Cost Results

This screen is only available for the **IGCC** plant type.

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<i>₿</i>			Cost (	Component		M\$	/yr	\$/MWh	Perce	nt Total		
11 27		1 Anno 2 Anno	ual Fixed Cost ual Variable Co	ost		4.8	60 70	1.671	8.	527 7.90		
<b>←</b>		4 Annu 5 Tota	l Annual Ozziv. ualized Capital l Levelized An	l Cost Cost nual Cost		43. 13. 56.	43 99	14.98 4.619 19.59	23	3.57 00.0		
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	Process Type:	2. Selex	col CO2 Cap	ture 💌	1		Costs are	e in Consta	ut 2005 d	dollars.		
	<u>1</u> . Diagram	<u> </u>	. Syngas	<u>3</u> . Capital C	Cost /	<u>4</u> .08	M Cost	<u>5</u> . T	otal Cos	t 🖉	i. Cost Fact	ors

Selexol CO₂ Capture – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Selexol CO₂ Capture Unit**. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

## **Cost Component**

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

## Selexol CO₂ Capture Cost Factors Results

This screen is only available for the **IGCC** plant type.

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			b	nportant	Perform	nce and Cost I	Factors	Value			Cost	of CO2 Avoided		Value
B		1	l Ne	et Plant S	Size (MW)			498.5		1	C	apture Plant		
100	Ш	2	2 A:	nnual Op	oerating H	ours (hours)		6575		2	CO2 Emissions (	lbs/kWh)		0.2919
	Ш	3	3							3	Cost of Electricit	y (\$/MWh)		66.77
?	Ш	4	l Fi	xed Char	ge Factor	(fraction)		0.148	0	4				
▶?	Ш	1	5							5	Re	<u>ference Plant</u>		
	Ш	Ć	5							6	CO2 Emissions (	lbs/kWh)		1.824
	Ш	2	7							7	Cost of Electricit	y (\$/MWh)		49.29
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	Ш		)							9	Cost of CO2 Ave	oided (\$/ton)		22.82
	Ш	1	0						_	10				
		1	1						_	11				
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Selexol CO₂ Capture – Cost Factors results screen.

#### **Important Performance and Cost Factors**

This screen displays information that is a key to the model calculations. The data is available else where in the model.

- **Net Plant Size (MW):** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).
- Annual Operating Hours (hours): This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days or 8,760 hours/year.
- **Fixed Charge Factor (fraction):** The fixed charge factor is one of the most important parameters in the IECM. It determines the revenue required to finance the power plant based on the capital expenditures. Put another way, it is a levelized factor which accounts for the revenue per dollar of total plant cost that must be collected from customers in order to pay the carrying charges on that capital investment.

#### Cost of CO₂ Avoided

#### **Capture Plant**

- **CO₂ Emissions (lbs/kWh):** This is the amount of CO₂ vented to the air for every kilowatt hour of electricity produced in the power plant that is using a CO₂ Capture technology.
- **Cost of Electricity (\$/MWh):** The IECM framework calculates the cost of electricity (COE) for the overall capture plant by dividing the total annualized plant cost (\$/yr) by the net electricity generated (kWh/hr).

#### **Reference Plant**

- **CO2 Emissions (lbs/kWh):** This is the amount of CO₂ vented to the air for every kilowatt hour of electricity produced in the power plant with no CO₂ capture.
- **Cost of Electricity (\$/MWh):** The IECM framework calculates the cost of electricity (COE) for the overall reference plant by dividing the total annualized plant cost (\$/yr) by the net electricity generated (kWh/hr).
- **Cost of CO₂ Avoided (\$/ton):** This is the economic indicator widely used in the field, calculated as the difference between the cost of electricity in the capture plant and the reference plant divided by the difference between the  $CO_2$  emissions in the reference plant and the capture plant.

Cost of CO2 Avoided = (Cost of Electricity cap – Cost of Electricity ref) / (CO2 emissions ref – CO2 emissions cap)

# Water Gas Shift Reactor

## Water Gas Shift Reactor Performance Inputs

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*		1	Water-Gas S	Shift Reactor									
		2	CO to CO2 Conve	rsion Efficiency	%			95.00	M	0.0	100.0	calc	
		3	COS to H2S Conv	version Efficiency	%			98.50		0.0	100.0	98.50	
		4	Steam Added		mol H2O/n	no1CO		0.9900	V	0.0	100.0	calc	
		5	Maximum Train C	O2 Capacity	lb-mole	s/hr		1.500e+04		0.0	3.000e+04	1.500e+04	
		6	Number of Operat	ting Absorbers	integ	er		3	V	Menu	Menu	calc	
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<u>×</u>		9	7 Number of Spare Absorbers 8 9 Thermal Energy Credit		% MV	Vg		3.870		0.0	10.00	calc	
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Water Gas Shift Reactor – Performance input screen.

### Water Gas Shift Reactor Unit

- **CO to CO₂ Conversion Efficiency:** Most of the CO in the raw syngas is converted into  $CO_2$  through the **Water Gas Shift** reaction.  $CO_2$  is removed from the shifted syngas through a physical absorption unit. This variable is the percentage of CO that is converted to  $CO_2$  in the reaction.
- **COS to H_2S Conversion Efficiency:** COS is difficult to remove in the Selexol unit, so a polishing unit is added to convert COS to  $H_2S$ . This is the conversion efficiency of the polishing unit.
- **Steam Added:** This parameter determines the amount of water added to the shift reactor in converting CO to  $CO_2$ . The moles of steam added is proportional to the moles of CO converted.

- **Maximum Train CO₂ Capacity:** The maximum production rate of  $CO_2$  is specified here. It is used to determine the number of operating trains required.
- **Number of Operating Trains:** This is the total number of operating trains. It is used primarily to calculate capital costs. The value must be an integer
- **Number of Spare Trains:** This is the total number of spare trains. It is used primarily to calculate capital costs. The value must be an integer.
- **Thermal Energy Credit:** The **Water Gas Shift** reaction is an exothermic process, producing heat that can be extracted and converted to steam for use in generating electricity. This is the thermal energy credit for steam produced and used in the steam cycle.

# Water Gas Shift Reactor Retrofit Cost Inputs

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*		1	Capital Cost	Process Area									
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R		3	Low Temperature	Reactor	retro	5/new\$		1.000		0.0	10.00	1.000	
		4	Heat Exchangers		retro	i/new\$		1.000		0.0	10.00	1.000	
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Water Gas Shift Reactor – Retrofit Cost input screen.

The retrofit cost factor of each process is is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital cost directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Each Capital Cost Process Area is described briefly below.

### **Capital Cost Process Area**

- **High Temperature Reactor:** This area accounts for the high temperature reactor vessel used for water gas shift. The iron-based catalyst is designed to be effective at high temperatures (650-1100 °F). The high temperature reactor has a high reaction rate and converts a large amount of CO into  $CO_2$ .
- **Low Temperature Reactor:** This area accounts for the low temperature reactor vessel used for water gas shift. The copper-based catalyst is designed to be effective at lower temperatures (450-650 °F). The low temperature reactor has a lower reaction rate, but converts a very high percentage of the remaining CO into CO₂.
- **Heat Exchangers:** The water gas shift process involves substantial cooling because of the exothermic reaction. Heat is recovered and temperature control is maintained through heat exchangers added after each reactor. This process area accounts for the heat exchangers used. Steam generated in the heat exchangers is sent to the steam cycle.

## Water Gas Shift Reactor Capital Cost Inputs

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2									
3	General Facilities	Capital	%PFC		15.00		0.0	50.00	15.00
4	Engineering & H	ome Office Fees	%PFC		10.00		0.0	50.00	10.00
5	Project Continge	ncy Cost	%PFC		15.00		0.0	100.0	15.00
6	Process Conting	ency Cost	%PFC		5.000		0.0	100.0	5.000
7	Royalty Fees		%PFC		0.5000		0.0	10.00	0.5000
8									
9	Pre-Produ	uction Costs							
10	Months of Fixed	0&M	month	s	1.000		0.0	12.00	1.000
11	Months of Variat	ble O&M	month	s	1.000		0.0	12.00	1.000
12	Misc. Capital Co	st	%TPI		2.000		0.0	10.00	2.000
13									
14	Inventory Capita	1	%TPC	:	0.5000		0.0	10.00	0.5000
15									
16									
17									
18	TCR Recovery F	actor	%		100.0		0.0	200.0	100.0
Pro			_	7					

Water Gas Shift Reactor – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

**Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

- **General Facilities Capital (GFC)**: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to

the architect/engineering company. These fees typically range from 7-15%.

- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.
  - **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
  - **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
  - **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

## Water Gas Shift Reactor O&M Cost Inputs

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X		1	High Temperatur	e Catalyst Cost	\$/ci	ıft		60.10		0.0	100.0	Calc	
30		2	Low Temperature	e Catalyst Cost	\$/c1	ı ft		300.5	M	0.0	500.0	Calc	
all		3	Water Cost		\$/100	0 gal		0.8316	V	0.0	2.500	calc	
		4	Electricity Price (	Base Plant)	\$/M	Wh		61.06		0.0	200.0	calc	
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←		6	Number of Opera	ting Jobs	jobs/	shift		1.000		0.0	30.00	1.000	
		7	Number of Opera	ting Shifts	shifts	/day		4.750		0.0	10.00	4.750	
<u>_</u>		8	Operating Labor	Rate	\$/1	л.		24.82		0.0	100.0	24.82	
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Water Gas Shift Reactor – O & M Cost input screen.

Inputs for O&M costs are entered on the **Water Gas Shift Reactor O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

- **High Temperature Catalyst Cost:** This is the unit cost of the ironbased high temperature catalyst.
- Low Temperature Catalyst Cost: This is the unit cost of the copperbased low temperature catalyst.
- Water Cost: This is unit cost of water used to drive the water gas shift reaction.
- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as the air separation unit, gasifier, and the power block.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work ( 3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)
- **Operating Labor Rate:** This is the hourly cost of labor for maintenance, administrative, and support personnel. The same rate is applied to all jobs across all technologies in the power plant.

- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- **Maint. Cost Allocated to Labor:** Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

## Water Gas Shift Reactor Diagram



Water Gas Shift Reactor – Diagram result screen.

The **Water Gas Shift Reactor Diagram** result screen displays an icon for the Water Gas Shift Reactor Unit and values for major flows in and out of it. Each result is described briefly below in flow:

- **Steam In:** This is the flow rate of steam added. The steam reacts with CO to produce  $H_2$  and  $CO_2$  in the presence of the catalyst in the two reactors.
- **Temperature In:** Temperature of the syngas entering the high temperature reactor.
- **Syngas In:** Flow rate of the syngas entering the high temperature reactor.
- **Temperature Out:** Temperature of the syngas exiting the final heat exhanger.
- **Syngas Out:** Flow rate of the syngas exiting the final heat exchanger.

## Water Gas Shift Reactor Syngas Results

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				Maj	or Syngas Com	ponents	Synas In (lb-moles/hr)	Syngas Out (Ib-moles/hr)	Syngas In (ton/hr)	Syngas Out (ton/hr)	
			1	Carbon Mo	noxide (CO)		1.837e+04	918.4	257.2	12.86	
-91			2	Hydrogen (	H2)		1.432e+04	3.177e+04	14.47	32.09	
			3	Methane (C	H4)		135.2	135.2	1.084	1.084	
2			4	Ethane (C2H	16)		0.0	0.0	0.0	0.0	
<b>N</b> ?			5	Propane (C3	3H8)		0.0	0.0	0.0	0.0	
			6	Hydrogen S	Sulfide (H2S)		247.5	247.5	4.217	4.217	
			7	Carbonyl Su	ulfide (COS)		14.15	14.15	0.4251	0.4251	
			8	Ammonia (1	4H3)		3.196	3.196	2.722e-02	2.722e-02	
			9	Hydrochlor	ic Acid (HCI)		0.0	0.0	0.0	0.0	
			10	Carbon Dio	xide (CO2)		4986	2.243e+04	109.7	493.7	
			11	Water Vapo	or (H2O)		6814	6639	61.39	59.82	
			12	Nitrogen (N	2)		352.5	352.5	4.937	4.937	
			13	Argon (Ar)			417.3	417.3	8.336	8.336	
			14	Oxygen (O2	)		0.0	0.0	0.0	0.0	
			15	Total			4.566e+04	6.294e+04	461.8	617.5	
		Process T	уре	: 1. Wate	er Gas Shift F	eactor 💌	,				
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Water Gas Shift Reactor – Syngas result screen.

### **Major Syngas Components**

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H₂):Total mass of hydrogen.

Methane (CH₄):Total mass of methane.

Ethane (C₂H₆):Total mass of ethane.

**Propane (C₃H₈):**Total mass of propane.

Hydrogen Sulfide (H₂S):Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH₃): Total mass of ammonia.

Hydrochloric Acid (HCI): Total mass of hydrochloric acid.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Water Vapor (H₂O): Total mass of water vapor.

Nitrogen (N₂): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O₂): Total mass of oxygen.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

## Water Gas Shift Reactor Capital Cost Results

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			Wat	er Gas Shift Pı	rocess Area Co	ists	Capital (M	Cost		Water Ga	as Shift Plant C	osts	Capital Cost (M\$)	
		1	High T	emperature Rea	actor	_	2.11	3	1	Process Facilitie	s Capital		44.05	
<b>1</b>		2	Low Te	mperature Rea	ctor		3.13	36	2	General Facilitie:	s Capital		6.608	
		3	Heat Ex	cchangers			38.8	30	3	Eng. & Home Of	fice Fees		4.405	
•		4	Process	s Facilities Cap	ital		44.0	)5	4	Project Continge	ency Cost		6.608	
$\rightarrow$		5							5	Process Conting	ency Cost		2.203	
91		6							6	Interest Charges	(AFUDC)		10.56	
2		7							7	Royalty Fees			0.2203	
<u>~  </u>		8							8	Preproduction (S	Startup) Cost		0.9575	
		9							9	Inventory (Worl	cing) Capital		0.3194	
		10							10	Total Capital Re	quirement (TCR	)	75.94	
		11							11					
		12							12					
		13							13					
		14							14					
		15							15	Effective TCR			75.94	
		Pro	cess Ty	pe: 1. Wate	er Gas Shift F	Reacte	or 💌	]		Costs are in	Constant 2005	dollars.		
			<u>1</u> . Diagr	am 🖌 :	2. Syngas	<u>} 3</u>	Capital (	Cost ,	<u> </u>	. O&M Cost /	<u>5</u> . Total Co	st /		

Water Gas Shift Reactor – Capital Cost result screen.

The **Water Gas Shift Reactor Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

### Water Gas Shift Reactor Process Area Costs

- **High Temperature Reactor:** This area accounts for the high temperature reactor vessel used for water gas shift. The iron-based catalyst is designed to be effective at high temperatures (650-1100 °F). The high temperature reactor has a high reaction rate and converts a large amount of CO into  $CO_2$ .
- **Low Temperature Reactor:** This area accounts for the low temperature reactor vessel used for water gas shift. The copper-based catalyst is designed to be effective at lower temperatures (450-650 °F). The low temperature reactor has a lower reaction rate, but converts a very high percentage of the remaining CO into CO₂.
- **Heat Exchangers:** The water gas shift process involves substantial cooling because of the exothermic reaction. Heat is recovered and temperature control is maintained through heat exchangers added after each reactor. This process area accounts for the heat exchangers used. Steam generated in the heat exchangers is sent to the steam cycle.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

#### Water Gas Shift Reactor Plant Costs

- Process Facilities Capital: (see definition above)
- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The percent of the water gas shift reactor TCR that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

## Water Gas Shift Reactor O&M Cost Results

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пI	5	Unti	tled*							
6	Ĺ		<u>C</u> onfigure Plant	Se	t <u>P</u> ara	me	ers	Í .	<u>G</u> et Resu	ılts
		Ove <u>r</u> a	11 Plant F <u>u</u> el <u>A</u> ir Separation	Gasifier Area	<u>S</u> ul Rem	fur oval	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stack
<b>3</b>			Variable Cost Component	O&M ( (M\$/y	ost r)		Fixed	Cost Componen	t	O&M Cost (M\$/yr)
2	Ш	1	High Temperature Catalyst	0.0		1	Operating Labor			0.3013
91	Ш	2	Low Temperature Catalyst	0.0		2	Maintenance La	bor		0.5110
	Ш	3	Electricity	0.0	_	3	Maintenance Ma	aterial		0.7665
-	Ш	4	Thermal Power Credit	-8.37	4	4	Admin. & Suppo	ort Labor		0.2437
2	Ш	5	Water	0.175	9	5	Total Fixed Cost	ទ		1.822
2	Ш	6	Total Variable Costs	-8.19	3	6				
?	Ш	7			-	7				
	Ш	8			-	8				
	Ш	10			-	, 10				
	Ш	11				11				
	Ш	12				12				
	Ш	13				13				
	Ш	14				14				
	Ш	15				15	Total O&M Cos	ts		-6.375
		Pre	cess Type: 1. Water Gas Shift Re	actor 💌			Costs are in	Constant 2005	dollars.	
			<u>1</u> . Diagram 🖌 <u>2</u> . Syngas 🖌	<u>3</u> . Capital C	ost	4	O&M Cost	<u>5</u> . Total Cos	st /	

Water Gas Shift Reactor – O & M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

#### Variable Cost Component

- **High Temperature Catalyst Cost:** This is the replacement cost of the iron-based high temperature catalyst. The initial cost is not included in this parameter.
- **Low Temperature Catalyst Cost:** This is the replacement cost of the copper-based low temperature catalyst. The initial cost is not included in this parameter.
- **Electricity:** The cost of electricity consumed by the water gas shift process areas.
- **Thermal Power Credit:** The credit for thermal power generated from steam provided by the heat exchangers in the water shift reactor vessels.
- **Water Cost:** This is total cost of water used to drive the water gas shift reaction.
- **Total Variable Costs:** This is the sum of all of the variable O&M costs listed above. This result is highlighted in yellow.

### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- **Admin. & Support Labor:** The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

## Water Gas Shift Reactor Total Cost Results

Ē	um Interrace Edit ⊻iew Go <u>W</u> in	idow <u>H</u>	elp								
	<u>C</u> onfi	gure F	'lant	S	et <u>P</u> araı	neters		Ĭ –	Ge	t Results	
	Overall Plant	F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfu Remov	r ral C	C <u>O</u> 2 apture	Power	Block	y-Prod. Mgmt	Stac <u>k</u>
			Cost	Component		M\$/yr	\$.	MWh	Percent 7	fotal	
I		1 A	nnual Fixed Cost			1.822	0	.6266	37.48	}	
1		2 A	annual Variable Co	ost		-8.198	-	2.818	-168.6	3	
II		3 T	otal Annual O&N	I Cost		-6.375	-	2.192	-131.1	1	
II		4 A	nnualized Capital	Cost		11.24		3.864	231.1	_	
II		5 T	otal Levelized An	nual Cost		4.863		.672	100.0	)	
II		6								_	
II		7								_	
II		8								_	
II		10					_			_	
II		11								_	
II		12					_				
II		13					_				
II		14									
I		15									
	Process Type:	1. W	ater Gas Shift F	teactor 💌	]	Co	sts are in	Constan	ıt 2005 doll	ars.	
	<u>1</u> . Diagram		<u>2</u> . Syngas	<u>3</u> .Capital(	Cost 🖌	<u>4</u> .0&M	Cost	<u>5</u> . T	otal Cost		

Water Gas Shift Reactor – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Water Gas Shift Reactor Unit**. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

### **Cost Component**

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# Sulfur Removal

 $SO_2$  emissions from IGCC systems are controlled by removing sulfur species from the syngas prior to combustion in the gas turbine. The syngas is assumed to be scrubbed of particulates prior to entering the sulfur removal system and is further cooled to 101 °F prior to entering a Selexol acid gas separation unit. H₂S and COS are removed from the syngas in the Selexol unit and sent to a Claus plant and a Beavon-Stretford tail gas treatment unit for sulfur recovery. The sulfur recovered can be sold as a by-product and credited to the sulfur removal technology area.

# **Sulfur Removal Performance Inputs**



Sulfur Removal – Performance input screen.

The acid gas removal system employs the Selexol process for selective removal of hydrogen sulfide (H₂S) and carbonyl sulfide (COS). Usually COS is present in much smaller quantities than H₂S. In this unit, most of the H₂S is removed by absorption in the Selexol solvent, with a typical removal efficiency of 95 to 98 percent. Typically only about one third of COS in the syngas will be absorbed. A hydrolyzer is used to convert the captured COS to H₂S in preparation for the stripping of H₂S from the Selexol solvent, along with sour gas from the process water treatment unit. This

concentrated gas stream is then sent to the Claus sulfur plant for recovery of elemental sulfur.

## Hydrolyzer (or Shift Reactor)

**COS to H₂S Conversion Efficiency:** This is the efficiency with which carbonyl sulfide is converted to hydrogen sulfide.

#### **Sulfur Removal Unit**

- $H_2S$  Removal Efficiency: This is the removal efficiency of  $H_2S$  from the inlet syngas stream. The  $H_2S$  is removed by an absorption process that is very effective at capture of  $H_2S$ .
- **COS Removal Efficiency:** This is the removal efficiency of COS. The absorption process is not very effective at capturing COS, so the removal efficiency default is very low.
- **CO₂ Removal Efficiency:** This is removal efficiency of CO₂ for the sulfur recovery system. This system is optimized to capture sulfurbearing components of a syngas, but maintains an affinity for CO₂. The CO₂ removed is eventually vented to the atmosphere from the Beavon-Stretford technology.
- Max Syngas Capacity per Train: This is the maximum flow rate of one Selexol-based sulfur recovery vessel. It is used to determine the number of absorber vessels required to treat the syngas.
- **Number of Operating Absorbers:** This is the number of absorbers required to treat the entire syngas stream. It is used primarily to determine the cost of the sulfur control area.
- **Power Requirement:** This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required. It is calculated as a function of the syngas flow rate.

## **Claus Plant**

- Sulfur Recovery Efficiency: This is the recovery efficiency of the Claus Plant in converting  $H_2S$  to elemental sulfur.
- Max Sulfur Capacity per Train: This is the maximum capacity of elemental sulfur from one Claus train.
- **Number of Operating Absorbers:** The number of trains is estimated from the recovered sulfur mass flow rate and the allowable range of recovered sulfur mass flow rate per train
- **Power Requirement:** This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required. It is calculated as a function of the sulfur flow from the Claus plant.

### **Tailgas Treatment**

(Note: The number of trains for this area is the same as the number of trains for the Claus plant process area.)

- **Sulfur Recovery Efficiency:** This is the recovery efficiency of the Beavon-Stretford plant in generating elemental sulfur. The remainder is oxidized to SO₂ and sent to a stack.
- **Power Requirement:** This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required for all three technologies above. It is calculated as a function of the sulfur flow rate from the Beavon-Stretford plant.

## **Sulfur Removal Retrofit Cost Inputs**

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ъI	5.	Untitled*										
6		<u>(</u>	<u>C</u> onfigure Plant	Ĩ	Set <u>P</u> ar	amete	ers	Ĩ		<u>G</u> et Res	ults	
		Ove <u>r</u> all Pla	nt F <u>u</u> el Sep	<u>A</u> ir aration	Gasifier Sul Area Rem	fur oval	C <u>O</u> 2 Captu	rePo	wer <u>B</u> lock	B <u>y</u> -Prod Mgmt	l. Sta	ic <u>k</u>
9	Ш		Title		Units	Unc	Value	Calc	Min	Max	Default	
*	Ш	1	Capital Cost Proce	ss Area								
	Ш	2	COS Conversion Syste	m - Hydrol	retro \$/new \$		1.000		0.0	10.00	1.000	
R.	Ш	3	Sulfur Removal System	- Selexol	retro \$/new \$		1.000		0.0	10.00	1.000	
	Ш	4	Sulfur Recovery Syster	n - Claus	retro \$/new \$		1.000		0.0	10.00	1.000	
B)	Ш	5	Tail Gas Treatment - Be	avon-Stret	retro \$/new \$		1.000		0.0	10.00	1.000	
←∥	Ш	6										
	Ш	7										
<u>_</u>	Ш	8										
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	Ш	11										
	Ш	12										
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	Ш	17										
	Ш	18										
		Proc	ess Type: Sulfur Ca	pture Syste	em 💌							
		<u>1</u> . Perf	ormance <u>2</u> . Retrof	it Cost	3. Capital Cost 🛛	4.0	D&M Cost	/				

Sulfur Removal – Retrofit Cost input screen.

#### **Capital Cost Process Area**

- **COS Conversion System Hydrolyzer:** The Hydrolyzer helps to separate the carbon from the sulfur by converting carbonyl sulfide to hydrogen sulfide.
- Sulfur Removal System Selexol: H₂S in the syngas is removed through counter-current contact with Selexol solvent. The cost of the Selexol section includes the acid gas absorber, syngas knock-out drum, syngas heat exchanger, flash drum, lean solvent cooler, mechanical refrigeration unit, lean/rich solvent heat exchanger, solvent regenerator, regenerator air-cooled overhead condenser, acid gas knock-out drum, regenerator reboiler, and pumps and expanders associated with the Selexol process.
- **Sulfur Recovery System Claus:** The Claus plant contains a twostage sulfur furnace, sulfur condensers, and catalysts.
- **Tail Gas Treatment Beavon-Stretford:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs.

All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

## **Sulfur Removal Capital Cost Inputs**

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ľ			<u>C</u>	onfigure Plant	Se	t <u>P</u> ar	amete	ers	Ĩ			<u>G</u> et Res	ults	
l	[	Ove <u>r</u> all F	lan	t F <u>u</u> el <u>A</u> ir Separation	Gasifier Area	<u>S</u> ul Rem	fur oval	C <u>O</u> 2 Captu	re	Pov	ver <u>B</u> lock	By-Prod Mgmt	. St	ac <u>k</u>
l		Γ		Title	Uni	s	Unc	Value	Ca	lc	Min	Max	Default	
II	II	1	ı [	Construction Time	yea	s		4.000			0.2500	10.00	4.000	
II	II	1	2											
II	II	1	3	General Facilities Capital	%PF	С		15.00			0.0	50.00	15.00	
II	II	4	1	Engineering & Home Office Fees	%PF	С		10.00			0.0	50.00	10.00	
II	II	4	5	Project Contingency Cost	%PF	C		15.00			0.0	100.0	15.00	
II	II		5	Process Contingency Cost	%PF	C		8.999	Ľ	1	0.0	100.0	calc	
II	II		7	Royalty Fees	%PF	С		0.5000			0.0	10.00	0.5000	
II	II	1	8											
II	II	9	9	Pre-Production Costs										
II	II	1	0	Months of Fixed O&M	mont	hs		1.000		0.0	12.00	1.000		
	II	1	1	Months of Variable O&M	mont	hs		1.000			0.0	12.00	1.000	
II	II	1	2	Misc. Capital Cost	%T	PI		2.000			0.0	10.00	2.000	
II	II	1	3						_	_				
I	1	1	4	Inventory Capital	%TI	°C		0.5000	-	_	0.0	10.00	0.5000	
		1	5						-	_				
		1	6						-	_				
I	1	1	7					400.0	-	_		200.0	100.0	
		1 Pr	8 oce	ss Type: Sulfur Capture Sys	tem %	v		100.0			0.0	200.0	100.0	

Sulfur Removal – Capital Cost input screen.

Inputs for capital costs are entered on the Capital Cost input screen.

**Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

- **General Facilities Capital (GFC)**: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.
  - **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
  - **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
  - **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

## Sulfur Removal O&M Cost Inputs

	<u>C</u> onfigure Plant	Set <u>P</u> ar	amet	ers			Get Res	ults
ve <u>r</u> all Pla	nt F <u>u</u> el <u>A</u> ir Separation	Gasifier Su Area Rem	lfur ioval	C <u>O</u> 2 Captu	ne Po	wer <u>B</u> lock	By-Prod Mgmt	l. 🚺 SI
	Title	Units	Unc	Value	Calc	Min	Max	Default
1	Selexol Solvent Cost	\$/16		2.320	V	0.0	10.00	calc
2	Claus Plant Catalyst Cost	\$/ton		565.8		0.0	1000	calc
3	Beavon-Stretford Catalyst Cost	\$/cuft		218.6		0.0	250.0	calc
4								
5	Sulfur Byproduct Credit	\$/ton		68.64		0.0	250.0	calc
6	Sulfur Disposal Cost	\$/ton		10.00		0.0	30.00	10.00
7 Sulfur Sold on Market		%		90.00		0.0	100.0	90.00
Surur Sold on Market Sectricity Price (Base Plant)		\$/MWh		61.06		0.0	200.0	calc
9								
10	Number of Operating Jobs	jobs/shift		6.670		0.0	30.00	6.670
11	Number of Operating Shifts	shifts/day		4.750		0.0	10.00	4.750
12	Operating Labor Rate	\$/hr		24.82		0.0	100.0	24.82
13								
14	Total Maintenance Cost	%TPC		2.000		0.0	10.00	calc
15	Maint. Cost Allocated to Labor	% total		40.00		0.0	100.0	40.00
16	Administrative & Support Cost	% total labor		30.00		0.0	100.0	30.00
17								
18								

#### Sulfur Removal – O&M Cost input screen.

Inputs for O&M costs are entered on the **Sulfur Removal O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

- Selexol Solvent Cost: This is the unit cost of Selexol.
- **Claus Plant Catalyst Cost:** This is the unit cost of catalyst used in the Claus plant.
- **Beavon-Stretford Catalyst Cost:** This is the unit cost of catalyst used in the Beavon-Stretford plant.
- **Sulfur Byproduct Credit:** This is the unit price of sulfur sold on the market.
- **Sulfur Disposal Cost:** This is the unit cost of any disposal wastes generated by the sulfur recovery processes.
- **Sulfur Sold on Market:** This is the fraction of the collected sulfur that is sold on the market. Any remaining sulfur is assumed to be utilized at no cost (i.e., neither disposed nor sold).
- **Electricity Price (Base Plant) :** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as the air separation unit, the gasifier, and the power block.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- **Maint. Cost Allocated to Labor:** Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

# Sulfur Removal Diagram



Sulfur Removal – Diagram result screen.

The **Sulfur Removal Diagram** result screen displays an icon for the **Sulfur Removal Unit (Selexol)**, the **Claus Plant**, the **Beavon Stretford Plant** and values for major flows in and out of it. The user may switch between the three process types' results by choosing from the pull down menu labeled **Process Type**, located above the bottom tabs on the left side of the **Sulfur Removal Diagram**. Each result shown on the **Sulfur Removal Diagram** is described briefly below in flow::

- **Temperature In:** Temperature of the syngas entering the Selexol-based sulfur removal unit.
- **Pressure In:** Pressure of the syngas entering the Selexol-based sulfur removal unit.
- **Syngas In:** Flow rate of the syngas entering the Selexol-based sulfur removal unit.
- **Makeup Solvent In:** This is the Selexol solvent makeup rate into the sulfur removal unit expressed on a continuous basis.
- **Makeup Catalyst In:** This is the catalyst makeup rate for the Claus plant expressed on a continuous basis.
- **Temperature Out:** Temperature of the syngas exiting the Selexol-based sulfur removal unit.
- **Pressure Out:** Pressure of the syngas exiting the Selexol-based sulfur removal unit.
- **Syngas Out:** Flow rate of the syngas exiting the Selexol-based sulfur removal unit.
- **Makeup Catalyst In:** This is the catalyst makeup rate for the Beavon-Stretford plant expressed on a continuous basis.

**Sulfur Out:** Flow rate of the elemental sulfur collected in both the Claus and Beavon-Stretford plants.

**Flue Gas Out:** The exhaust gas from the Beavon-Stretford plant is completely burned and sent to a stack. This is the flow rate of combusted exhaust gases.

# **Sulfur Removal Capital Cost Results**

	e onix	C			(	e	+ Der				C + D	1
		<u>c</u>	onfigure Pla	int		Se	t <u>P</u> ar	ame	ters		Get Resi	uts
	Over	all Plant	F <u>u</u> el	<u>A</u> ir Separation	Ga A	asifier Area	<u>S</u> u Rem	lfur oval	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stack
		Sul	fur Removal P	rocess Area Co	sts	Capital ( (M\$)	Cost )		Sulfur Re	moval Plant C	osts	Capital Cost (M\$)
	1	Sulfur	Removal Syste	m - Hydrolyzer	_	0.0		1	Process Facilities	Capital		34.06
l	2	Sulfur	Removal Syste	m - Selexol		22.81		2	General Facilities	Capital		5.109
	3	Sulfur	Recovery Syst	em - Claus		6.816	ŝ	3	Eng. & Home Off	ice Fees		3.406
	4	Tail G	as Clean Up - B	eavon-Stretford		4.43	5	4	Project Continger	ncy Cost		5.109
	5							5	Process Continge	ency Cost		3.065
	6							6	Interest Charges	(AFUDC)		8.393
	7							7	Royalty Fees			0.1703
	8							8	Preproduction (S	tartup) Cost		1.606
	9							9	Inventory (Work	ing) Capital		0.2537
	10							10	Total Capital Req	uirement (TCF	9	61.17
	11	Proces	s Facilities Cap	utal		34.06	6	11				
	12							12				
	13							13				
	14						_	14				
	15							15	Effective TCR			61.17
	Pr	ocess T	ype: 1. Sulf	ur Capture Sy	/stem	•			Costs are in (	Constant 2005	dollars.	

Sulfur Removal Capital Cost results screen.

The **Sulfur Removal Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

### **Sulfur Removal Process Area Costs**

- **Sulfur Removal System Hydrolyzer** This is the capital cost for the hydrolyzer system, which converts carbonyl sulfide to hydrogen sulfide.
- **Sulfur Removal System Selexol** H₂S in the syngas is removed through counter-current contact with Selexol solvent. The cost of the Selexol section includes the acid gas absorber, syngas knock-out drum, syngas heat exchanger, flash drum, lean solvent cooler, mechanical refrigeration unit, lean/rich solvent heat exchanger, solvent regenerator, regenerator air-cooled overhead condenser, acid gas knock-out drum, regenerator reboiler, and pumps and expanders associated with the Selexol process.
- **Sulfur Recovery System Claus** The Claus plant contains a two-stage sulfur furnace, sulfur condensers, and catalysts.

- **Tail Gas Clean Up Beavon-Stretford** The capital cost of a Beavon-Stretford unit varies with the volume flow rate of the input gas streams and with the mass flow rate of the sulfur produced. The regression model is based only on the sulfur produced by the Beavon-Stretford process.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

### **Sulfur Removal Plant Costs**

- Process Facilities Capital: (see definition above)
- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

# Sulfur Removal O&M Cost Results

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ы	5-	Unti	tled*									×
2			<u>C</u> onfigure Plant	Ĩ	Set	<u>P</u> ara	me	ers	l I	<u>G</u> et Resi	ılts	
	(	Dve <u>r</u> a	11 Plant Fuel Air Separat	ion Ga	asifier Area	<u>S</u> ulf Remo	lur oval	CO2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stack	
			Variable Cost Compon	ent	O &M Co: (M\$/yr)	st		Fixed	Cost Componen	t	O&M Cost (M\$/yr)	
1		1	Makeup Selexol Solvent		0.1548		1	Operating Labor			2.009	
ș1		2	Makeup Claus Catalyst		2.992e-0	3	2	Maintenance La	bor		0.4060	
-1		3	Makeup Beavon-Stretford Cata	yst	5.365e-0	3	3	Maintenance Ma	aterial		0.6090	
		4	Sulfur Byproduct Credit		1.568		4	Admin. & Suppo	ort Labor		0.7246	
		5	Disposal Cost		2.537e-0	2	5	Total Fixed Cost	s		3.749	
1		6	Selexol Electricity		2.003		6					
		7	Claus Electricity		0.1743	_	7					
비		8	Beavon-Stretford Electricity		0.5304		8					
		9	Total Variable Costs		1.328		9					
		10				-	10					
		11				_	11					
		12				-	12					
		13				-	13					
		14	14			-1	14	T-+-1 0 8 M C	<b>.</b>		6.070	
		Pro	cess Type: 1. Sulfur Captu	re System	•		15	Costs are in	Constant 2005	dollars.	3.078	
		<u> </u>	<u>1</u> . Diagram 🖌 <u>2</u> . Capital Co	ist 👌 🛾	. O&M Cost	: /	4	TotalCost /	/			1

Sulfur Removal – O&M Cost results screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

#### Variable Cost Component

- Makeup Selexol Solvent This is the annual cost of makeup Selexol.
- **Makeup Claus Catalyst** This is the annual cost of makeup catalyst used in the Claus plant.
- **Makeup Beavon-Stretford Catalyst** This is the annual cost of makeup catalyst used in the Beavon-Stretford plant.
- **Sulfur Byproduct Credit** This is the annual profit for sulfur sold on the market.
- **Disposal Cost** This is the annual cost of all wastes generated by the sulfur recovery processes and disposed.
- **Selexol Electricity** This is the annual cost of electricity used by the Selexol-based sulfur capture process area. It is based on the electricity price of the base plant and the power consumed in the process areas.
- **Claus Electricity** This is the annual cost of electricity used by the Claus plant process area. It is based on the electricity price of the base plant and the power consumed in the process areas.
- **Beavon-Stretford Electricity:** This is the annual cost of electricity used by the Beavon-Stretford process area. It is based on the electricity price of the base plant and the power consumed in the process areas.

**Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

#### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.
- **Admin. & Support Labor:** The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

## **Sulfur Removal Total Cost Results**

Ĩ	<u>C</u> onfigur	e Pla	nt	S	et <u>P</u> aran	neters	,			Get Res	ults
	Overall Plant Fue	el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfu Remov	al CO2 C	apture	Power	Block	By-Prod. Mgmt	Stac
			Cost	Component		M\$/yr	\$/	MWh	Perce	ent Total	
	1	Ant	nual Fixed Cost			3.749	1	289	2	6.53	
I	2	Anr	nual Variable Co	ost		1.328	0.	4567	9.	.401	
	3	Tot	al Annual O&N	I Cost		5.078	1	746	3	5.93	
I	4	Anr	nualized Capital	Cost		9.053	3	.112	6	4.07	
I	5	Tot	al Levelized An	nual Cost		14.13	4	858	1	00.0	
I	6										
I	7	_									
I	8	_									
I	9						_				
I		J									
1											
I		2									
I		1					-		-		
I	14										
	Process Type: 1	Sulfi	ir Capture Sv	/stem	7	Cost	s are in	Constan	t 2005	dollars.	

Sulfur Removal – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Sulfur Removal Unit**. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

## **Cost Component**

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

## Sulfur Removal Hydrolyzer Syngas Results

File	En En	<b>1 Interface</b> dit <u>V</u> iew <u>W</u> i	ndov	/ <u>H</u> elp							
ЪI		Untitled*									_ 🗆 ×
		<u>C</u>	on	figure Pla	int 🏻	Se	t <u>P</u> aramete	rs	<u>(</u>	<u>G</u> et Results	
		Overall Plan	ıt	F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	CO2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac <u>k</u>
× 4				Maj	or Syngas Con	<b>ponents</b>	Syngas In (B-moles/hr)	Syngas Out (Ib-moles/hr)	Syngas In (ton/hr)	Syngas Out (ton/hr)	
E			1	Carbon Mo	noxide (CO)		1.825e+04	1.825e+04	255.6	255.6	
			2	Hydrogen (	H2)		1.416e+04	1.416e+04	14.30	14.30	
			3	Methane (C	H4)		108.0	108.0	0.8660	0.8660	
2			4	Ethane (C2F	H6)		0.0	0.0	0.0	0.0	
N?			5	Propane (C3	3H8)		0.0	0.0	0.0	0.0	
			6	Hydrogen S	Sulfide (H2S)		465.9	492.4	7.939	8.390	
			7	Carbonyl St	ulfide (COS)		26.88	0.4032	0.8073	1.211e-02	
			8	Ammonia (1	NH3)		3.301	3.301	2.811e-02	2.811e-02	
			9	Hydrochlor	ic Acid (HCI)		0.0	0.0	0.0	0.0	
			10	Carbon Dio	xide (CO2)		5652	5678	124.4	125.0	
			11	Water Vapo	or (H2O)		7682	7656	69.22	68.98	
			12	Nitrogen (N	2)		363.6	363.6	5.092	5.092	
			13	Argon (Ar)			442.8	442.8	8.844	8.844	
			14	Oxygen (O2	0		0.0	0.0	0.0	0.0	
			15	Total			4.715e+04	4.715e+04	487.1	487.1	
		Process '	Туре	2. Hydr	olyzer	•					
		<u>1</u> . Sy:	ngas								

Sulfur Removal Hydrolyzer Syngas results screen.

## Major Syngas Components

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H₂):Total mass of hydrogen.

Methane (CH₄): Total mass of methane.

**Ethane (C₂H₆):** Total mass of ethane.

Propane (C₃H₈): Total mass of propane.

Hydrogen Sulfide (H₂S):Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH₃): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Water Vapor (H₂O): Total mass of water vapor.

Nitrogen (N₂): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O₂): Total mass of oxygen.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

## Sulfur Removal Selexol Sulfur System Syngas Results

,	<u>C</u>	oni	figure Pla	int	Se	t <u>P</u> arameter	s	(	Get Results	
	Ove <u>r</u> all Plant		F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	Sulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac
			Maj	or Syngas Con	ponents	Syngas In (Ib-moles/hr)	Syngas Out (Ib-moles/hr)	Syngas In (ton/hr)	Syngas Out (ton/hr)	
	1	1	Carbon Mo	noxide (CO)		912.6	912.6	12.78	12.78	
	<b>  </b> i	2	Hydrogen (	H2)		3.150e+04	3.150e+04	31.81	31.81	
	<b>  </b> [	3	Methane (C	H4)		108.0	108.0	0.8660	0.8660	
1	<b>   </b> 1	4	Ethane (C2H	H6)		0.0	0.0	0.0	0.0	
11	III ī	5	Propane (C3	3H8)		0.0	0.0	0.0	0.0	
1		6	Hydrogen S	Sulfide (H2S)		492.4	9.847	8.390	0.1678	
		7	Carbonyl St	ulfide (COS)		0.4032	0.2701	1.211e-02	8.113e-03	
		8	Ammonia (1	NH3)		3.301	3.301	2.811e-02	2.811e-02	
		9	Hydrochlor	ic Acid (HCl)		0.0	0.0	0.0	0.0	
		10	Carbon Dio	xide (CO2)		2.302e+04	2.302e+04	506.5	506.5	
		11	Water Vapo	or (H2O)		7483	7483	67.42	67.42	
		12	Nitrogen (N	2)		363.6	363.6	5.092	5.092	
		13	Argon (Ar)			442.8	442.8	8.844	8.844	
		14	Oxygen (O2	0		0.0	0.0	0.0	0.0	
	<b>  </b> .	15	Total			6.432e+04	6.384e+04	641.8	633.5	
	Process	Tune	2 Cala	und Cultur C	unter un					

Selexol Sulfur System Syngas results screen.

#### **Major Syngas Components**

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H₂):Total mass of hydrogen.

Methane (CH₄):Total mass of methane.

Ethane (C₂H₆): Total mass of ethane.

Propane (C₃H₈): Total mass of propane.

Hydrogen Sulfide (H₂S):Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH₃): Total mass of ammonia.

Hydrochloric Acid (HCI): Total mass of hydrochloric acid.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Water Vapor (H₂O): Total mass of water vapor.

Nitrogen (N₂): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O₂): Total mass of oxygen.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

## **Sulfur Removal Claus Plant Air Results**

©∭	<u>C</u> onfigu	re Plant	t Ì	S	et <u>P</u> aramete	ers		Get Results	
	Overall Plant F1	1e1	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac <u>k</u>
∰ ∦ }			м	ajor Gas Comp	onents	Air In (B-moles/hr)	Air In (ton/hr)		
		1	Carbon Mo	noxide (CO)		0.0	0.0		
		2	Hydrogen (	H2)		0.0	0.0	-	
		3	Methane (C	H4)		0.0	0.0		
?∭		4	Ethane (C2H	16)		0.0	0.0		
?		5	Propane (C.	3H8)		0.0	0.0		
<u>.                                    </u>		6	Hydrogen S	ulfide (H2S)		0.0	0.0		
		7	Carbonyl S	ulfide (COS)		0.0	0.0		
		8	Ammonia (1	VH3)		0.0	0.0		
		9	Hydrochlor	ic Acid (HCl)		0.0	0.0	_	
		10	Carbon Dio	xide (CO2)		0.0	0.0	_	
		11	Water Vapo	r (H2O)		0.0	0.0	_	
		12	Nitrogen (N	2)		861.8	12.07	_	
		13	Argon (Ar)			0.0	0.0	_	
		14	Oxygen (O2	)		229.2	3.667		
		15	Total			1091	15.74		

Sulfur Removal Claus Plant Air results screen.

### **Major Syngas Components**

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H₂):Total mass of hydrogen.

Methane (CH₄):Total mass of methane.

Ethane (C₂H₆): Total mass of ethane.

Propane (C₃H₈): Total mass of propane.

Hydrogen Sulfide (H₂S):Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH₃): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Water Vapor (H₂O): Total mass of water vapor.

Nitrogen (N₂): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O₂): Total mass of oxygen.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

## **Sulfur Removal Claus Plant Treated Gas Results**

-	-	Con	figure Pla	nt	Se	t Parameter	·c 1		Gat Daculto	
411	<u>-</u>		ingui e i la	in I	50				Jet Results	
	Ove <u>r</u> all Pla	nt	F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac <u>k</u>
3			M	ajor Gas Comp	onents	Gas In ( <b>b</b> -moles/hr)	Gas Out (B-moles/hr)	Gas In (ton/hr)	Gas Out (ton/hr)	
		1	Carbon Mo	noxide (CO)		0.0	0.0	0.0	0.0	
궤		2	Hydrogen (	H2)		0.0	0.0	0.0	0.0	
		3	Methane (C	H4)		0.0	0.0	0.0	0.0	
2		4	Ethane (C2F	16)		0.0	0.0	0.0	0.0	
2		5	Propane (C3	H8)		0.0	0.0	0.0	0.0	
-11		6	Hydrogen S	ulfide (H2S)		482.5	24.13	8.222	0.4111	
		7	Carbonyl Sı	ilfide (COS)		0.1330	0.1330	3.996e-03	3.996e-03	
		8	Ammonia (1	amonia (NH3)		0.0	0.0	0.0	0.0	
		9	Hydrochlori	ic Acid (HCl)		0.0	0.0	0.0	0.0	
		10	Carbon Dio	ride (CO2)		0.0	0.0	0.0	0.0	
		11	Water Vapo	r (H2O)		0.0	458.4	0.0	4.130	
		12	Nitrogen (N	2)		0.0	861.8	0.0	12.07	
		13	Argon (Ar)			0.0	0.0	0.0	0.0	
		14	Oxygen (O2	)		0.0	1.526e-05	0.0	2.441e-07	
		15	Total			482.6	1344	8.226	16.61	
	Process	Туре	4. Clau	s Plant	•					

Sulfur Removal Claus Plant Treated Gas results screen.

## **Major Syngas Components**

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H₂):Total mass of hydrogen.

Methane (CH₄):Total mass of methane.

Ethane (C₂H₆): Total mass of ethane.

Propane (C₃H₈): Total mass of propane.

Hydrogen Sulfide (H₂S):Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH₃): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Water Vapor (H₂O): Total mass of water vapor.

Nitrogen (N₂): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O₂): Total mass of oxygen.

# Sulfur Removal Beavon Stretford Plant Treated Gas Results

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	ľ	<u>C</u> onfigure P	lant		Se	t <u>P</u> aramete	ers 🏾		Get Results	1
		Overall Plant Fuel		<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac <u>k</u>
8 8 8				м	ajor Gas Compo	onents	Gas In (B-moles/hr)	Gas In (ton/hr)		
	l		1	Carbon Mo	noxide (CO)		0.0	0.0	-	
P	l		2	Hydrogen (	H2)		0.0	0.0		
	l		3	Methane (C	H4)		0.0	0.0		
<u>*</u>	l		4	Ethane (C2B	16)		0.0	0.0		
	l		5	Propane (C.	3H8)		0.0	0.0		
	l		6	Hydrogen S	ulfide (H2S)		226.9	0.1933		
	l		7	Carbonyl S	ulfide (COS)		0.0	0.0		
	l		8	Ammonia (1	4H3)		0.0	0.0		
	l		9	Hydrochlor	ic Acid (HCI)		0.0	0.0		
	l		10	Carbon Dio	nide (CO2)		686.5	15.11		
	l		11	Water Vapo	r (H2O)		0.0	1.942		
	I		12	Nitrogen (N	2)		0.0	5.676		
	I		13	Argon (Ar)			0.0	0.0		
	l		14	Oxygen (O2	)		0.0	0.0		
	l		15	Total			913.4	22.92		
		Process Type: 3. Be	avo	n-Stretford		_				
	I	<u>I. Treated Gas</u>	<u>∠</u> . P	IGE GRS						

Sulfur Removal Beavon Stretford Plant Treated Gas results screen.

## **Major Syngas Components**

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H₂):Total mass of hydrogen.

Methane (CH₄):Total mass of methane.

Ethane (C₂H₆): Total mass of ethane.

Propane (C₃H₈): Total mass of propane.

Hydrogen Sulfide (H₂S):Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH₃): Total mass of ammonia.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO2): Total mass of carbon dioxide.

Water Vapor (H₂O): Total mass of water vapor.

Nitrogen (N₂): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O₂): Total mass of oxygen.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

## **Sulfur Removal Beavon Stretford Plant Flue Gas Results**

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	Ove <u>r</u> all Plant	Fuel	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac <u>k</u>
*			м	ajor Gas Compo	ments	Tail Gas Out (B-moles/hr)	Tail Gas Out (ton/hr)		
		1	Nitrogen (N	2)		427.0	5.981	1	
e l		2	Oxygen (O2	)		0.0	0.0	1	
		3	Water Vapo	r (H2O)		226.9	2.045	]	
<u>*</u>		4	Carbon Dio	xide (CO2)		686.5	15.11		
		4	Carbon Mo	noxide (CO)		0.0	0.0		
		6	Hydrochlor	oric Acid (HCl) 0.0			0.0		
		2	' Sulfur Dioxi	Dioxide (SO2)			3.634e-03		
		٤	Sulfuric Ac	id (equivalent S	D3)	0.0	0.0		
		9	Nitric Oxide	(NO)		1.146e-02	1.720e-04		
		1	0 Nitrogen Di	oxide (NO2)		6.033e-04	1.388e-05		
		1	1 Ammonia (1	1H3)		0.0	0.0		
		1	2 Argon (Ar)			0.0	0.0		
		1	3 Total			1341	23.14		
		1	4					-	
	Process Type:	3. Beav							
	<u>1</u> . Treated Gas	2	Flue Gas						

Sulfur Removal Beavon Stretford Plant Flue Gas Results

#### **Major Flue Gas Components**

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid (on an SO₃equivalency basis).

Nitric Oxide (NO): Total mass of nitric oxide.
Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **By Product Management**

The **ByProduct <u>Mgmt</u>** Technology Navigation Tab screens display and design the management of by products and waste disposal.

### **By Product Management Performance Inputs**

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		Overall Plant	F <u>u</u> el	Base Plant Const	sion r <u>a</u> int Mercu	ury Cor	Dx <u>]</u> itro1 Cc	[SP introl	<u>S</u> O2 Control	C <u>O</u> Capt	2 By- ure <u>M</u>	Prod. gmt
5	III			Title	Units	Unc	Value	Calc	Min	Max	Default	
¥1	Ш	1	Bottom Ash F	ond Energy Require	. %		0.0		0.0	25.00	0.0	
30	Ш	2	Fly Ash Disp	osal Power Requirem.	%		0.0		0.0	30.00	0.0	
	Ш	3	Flue Gas Was	te Disposal Power R	. %		0.0		0.0	25.00	0.0	
	Ш	4										
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		Proc	ess Type: 🛛	/aste Managemen	t r	-				-		
		<u>1</u> . Perf	ormance	2. Sequest.								

By Product Management – Performance input screen.

General inputs regarding solid waste management are entered on the **Performance** input screen. This screen is displayed for all plant configurations. One or more of the following By Product Management options will be shown on the input screen depending upon the options selected in the **Configure Plant** program area. Each of the possible parameters are described briefly below.

- **Bottom Ash Pond Energy Requirements:** The energy requirement is zero by default. Any requirements are considered by the abatement technologies that dispose solids into the bottom ash pond.
- Fly Ash Disposal Power Requirements: The energy requirement is zero by default. Any requirements are considered by the abatement technologies that dispose of fly ash.

Flue Gas Waste Disposal Power Requirements: The energy

requirement is zero by default. Any requirements are considered by the abatement technologies that dispose of flue gas waste.

### **By Product Management Sequestration Input**



By Product Management – Sequestration input screen.

If the user has selected **CO₂ Capture** in the **Configure Plant** program area this input screen will also be available. Its parameter is described briefly below.

**Sequestration Power Requirement:** The energy requirement is zero by default.

## By Products Management Bottom Ash Pond Diagram

The **By Product Management** Technology Navigation Tab screens displays the flow rates of solid and liquid substances collected which require management (disposal or recovery). There are three **By Product Management** areas, **Bottom Ash Pond, Flue Gas Treatment** and **Fly Ash Disposal**. If **CO**₂ Capture has been configured for the plant by the user then a **Geological Reservoir** is also available. These are accessed by the **Process Type** drop-down menu. Each

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	Overail F <u>u</u> el <u>B</u> oiler	Air         MOx         Mercury         TSP         SO2         CO2         By-Frod.           Preheater         Control         Control         Control         Magnet	Stac <u>k</u>
		Wet Bottom Ash (ton/hr) 2.432 Mercury (lb/hr) 2.659e-03	
		Wet Fly Ash (ton/hr) 0.0 Mercury (lb/hr) 0.0	
		Wet Total Solids (ton/hr) 2.432	
	Process Type: Bottom Ast	Total Mercury (lb/hr) 2.659e-03 Pond	
		CM Interface Edit View Window Help Configure Plant Overall Fuel Boiler Plant Fuel Boiler Process Type: Bottom Ash 1. Diagram	CM Interface Edit View Window Help Configure Plant Set Parameters Get Results Overall Fuel Boiler Air NOx Mercury TSP SO2 CQ2 Capture By-Prod Plant Fuel Boiler Air Control Mercury Control Control Capture Mercury Wet Bottom Ash (ton/hz) 2.432 Mercury (b/hz) 2.659e-03 Wet Fly Ash (ton/hz) 0.0 Mercury (b/hz) 0.0 Wet Total Solids (ton/hz) 2.432 Total Mercury (lb/hz) 2.659e-03 Process Type: Bottom Ash Pond

management technology has only one Result Navigation Tab: **Diagram**.

By Products Management Bottom Ash Pond—Diagram result screen

The **Bottom Ash Pond Diagram** result screen displays an icon for the **Pond** and values for major flows into it. Each result is described briefly below:

#### **Bottom Ash Pond Inputs**

Solids mixed with sluice water that are collected in the bottom of the boiler and by the particulate removal technologies are transported to the Pond for treatment. The IECM currently provides no additional treatment or consideration of these substances, and therefore simply reports the quantities entering the technology.

Wet Bottom Ash: Mass flow rate of bottom ash solids on a wet basis.

- **Mercury (contained in Bottom Ash):** Mass flow rate of mercury present in the bottom ash solids on a wet basis.
- Wet Fly Ash: Mass flow rate of total fly ash solids on a wet basis. This value is zero when the fly ash is disposed in a landfill.
- **Mercury (contained in Fly Ash):** Mass flow rate of mercury present in the fly ash solids on a wet basis.

#### **Bottom Ash Pond – Totals**

- Wet Total Solids: The sum of the fly ash and bottom ash solids on a wet basis.
- **Total Mercury:** Mass flow rate of mercury present in the combined bottom ash and fly ash solids on a wet basis.

### By Products Management Flue Gas Treatment Diagram

The **By Product Management** Technology Navigation Tab screens displays the flow rates of solid and liquid substances collected which require management (disposal or recovery). There are three **By Product Management** areas, **Bottom Ash Pond**, **Flue Gas Treatment** and **Fly Ash Disposal**. If CO₂ capture has

been configured for the plant by the user then a **Geological Reservoir** is also available. These are accessed by the **Process Type** drop-down menu. Each management technology has only one Result Navigation Tab: **Diagram**.

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	ľ	Overall Fuel Boiler Air NOx Mercury ISP SO2 CO2 By-Prod. St Plant Fuel Boiler Preheater Control Mercury Control Control Capture Mgmt St	ac <u>k</u>
		Wet Fly Ash (ton/hr) Mercury (lb/hr) 0.0 Wet FGD Solids (ton/hr) 17.42 Mercury (lb/hr) 2.304e-02 Wet Total Solids (ton/hr) 17.42 Total Mercury (lb/hr) 2.304e-02 Process Type: Flue Gas Treatment 1 Diagram	

By Products Management Bottom Ash Pond—Diagram result screen

The **Flue Gas Treatment Diagram** result screen displays an icon for the **Landfill** and values for major flows into it. Each result is described briefly below:

#### Flue Gas Treatment Inputs

Solids mixed with sluice water that are collected in the bottom of the boiler and by the particulate removal technologies are transported to the Pond for treatment. The IECM currently provides no additional treatment or consideration of these substances, and therefore simply reports the quantities entering the technology.

Wet FGD Solids: Mass flow rate of wet FGD solids.

- Mercury (contained in Wet FGD Solids): Mass flow rate of mercury present in the Wet FGD solids.
- Wet Fly Ash: Mass flow rate of total fly ash solids on a wet basis. This value is zero when the fly ash is disposed in a landfill.
- **Mercury(contained in Fly Ash):** Mass flow rate of mercury present in the fly ash solids on a wet basis.

#### Flue Gas Treatment – Totals

- Wet Total Solids: The sum of the wet FGD solids and the fly ash on a wet basis.
- **Total Mercury:** Mass flow rate of mercury present in the combined wet FGD solids and fly ash solids on a wet basis.

### By Products Management Fly Ash Disposal Diagram

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		Overall Plant	Fuel	<u>B</u> oiler	<u>A</u> ir Preheate	r <u>N</u> Ox Control	Mercury	<u>T</u> SP Control	<u>S</u> O2 Control	C <u>O</u> 2 Capture	By-Prod. <u>M</u> gmt	Stac <u>k</u>
		Process T	Vpe:	/ Ách Die		Wet Fly Ash ( Mercury (lb/hr Wet Total Soli Total Mercury	ton/hr) ) ds (ton/hr) (lb/hr)	23.56 1.095e-02 23.56 1.095e-02				
		1. Diag	ram /	ASN DIS	posal		_	_	_	_	_	
			/									

By Products Management Fly Ash Disposal—Diagram result screen

The **By Products Management Fly Ash Disposal Diagram** result screen displays an icon for the **Landfill** and values for major flows into it. This screen is only an option if **CO₂ Capture** has been configured for the plant by the user. Each result is described briefly below:

#### Fly Ash Disposal Inputs

Solids mixed with sluice water are collected in the particulate removal technologies and may be transported to the Landfill for treatment. The IECM currently provides no additional treatment or consideration of these substances, and therefore simply reports the quantities entering the technology.

Wet Fly Ash: Mass flow rate of total fly ash solids on a wet basis.

**Mercury**: Mass flow rate of mercury present in the fly ash solids on a wet basis.

#### Fly Ash Disposal Totals

Wet Total Solids: The sum of the fly ash and FGD solids on a wet basis.

**Total Mercury:** Mass flow rate of mercury present in the combined fly ash and FGD solids on a wet basis.

# By Products Management Geological Resevoir Diagram



By Product Management – Geological Reservoir diagram.

The **By Products Management Geological Reservoir Diagram** result screen displays an icon for the **Geological Reservoir** and values for the concentrated  $CO_2$  that flows into it. The result is described briefly below:

Condensed CO₂: Mass flow rate of CO₂.

# **CO₂ Transport System**

The  $CO_2$  Transport System models the transport via pipeline of carbon dioxide ( $CO_2$ ) captured at a power plant from plant site to sequestration site. It may be used in all of the plant type configurations.

## **CO₂ Transport System Configuration**

This screen is available for all plant types. The screens under the  $CO_2$  Capture Technology Navigation Tab display and design flows and data related to the  $CO_2$ Transport System.

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	2	Net Pip	oline El	evation Chang	ge (P1a		feet		0.0		0.0	328.1	0.0	
	3	Numbe	r of Bo	oster Stations		i	nteger		0.0	V	0.0	10.00	Calc	
1	4	Compr	essor/F	'ump Driver					Electric	-	Menu	Menu	Electric	
	5	Booste	er Pump	Efficiency			%		75.00		0.0	100.0	75.00	
11	6	i												
	7	Design	n Pipelir	ne Flow (% pla	int cap)		%		100.0		100.0	500.0	100.0	
	8	Actual	Pipelin	le Flow		t	ons/yr		2.677e+0	6 🗹	0.0	None	Calc	
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CO₂ Transport System – Config. input screen.

Each configuration parameter is described briefly below.

**Total Pipeline Length:** This is the total length of the pipe between the plant site and the sequestration site.

**Net Pipeline Elevation Change (Plant->Injection):** The pipeline may traverse hilly terrain; this is the overall elevation change from plant site to injection site.

- **Number of Booster Stations:** The cost of CO₂ transport may be lowered by adding booster stations for longer pipeline lengths. This is the number of those stations that are to be modeled.
- **Compressor/Pump Driver:** This is the type of motor that drives the compressor or pump; electric, diesel or natural gas.
- **Booster Pump Efficiency:** This is the efficiency of the pump, and accounts for all frictional losses.
- **Design Pipeline Flow (% plant cap):** This is the flow of liquid CO₂ that the pipeline has been designed to handle as a percent of the total that the plant is capable of producing.
- **Actual Pipeline Flow:** This is the amount of liquid CO₂ that flows through the pipeline in tons per year.
- **Inlet Pressure (@ power plant):** The inlet pressure is shown here for reference only and may be modified in the parameters for the CO₂ capture device (e.g., amine scrubber, selexol scrubber)
- **Min. Outlet Pressure (@ storage site):** This the minimum outlet pressure of the  $CO_2$  at the storage site
- **Average Ground Temperature:** This is the average temperature of the ground where the pipeline will traverse.
- **Pipe Material Roughness:** The roughness measure is the average size of the bumps on the pipe wall, for commercial pipes this is usually a very small number. Note that perfectly smooth pipes would have a roughness of zero.

### CO₂ Transport System Financing Inputs

This screen is available for all plant types.

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X		1	Pipeline Region				Midwest 💌		Menu	Menu	vlidwest US	
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CO₂ Transport System –Financing input screen.

- **Pipeline Region:** This is the region of the U.S. where the project will be built; central, mid-west, northeast, southeast or western. These regions are based on the EIA natural gas pipeline regions.
- **Year Costs Reported:** This is the year in which all costs are given or displayed, both in the input screens and the results. A cost index is used by the IECM to scale all costs to the cost year specified by this parameter.
- **Discount Rate (Before Taxes):** This is also known as the cost of money. Discount rate (before taxes) is equal to the sum or return on debt plus return on equity, and is the time value of money used in before-tax present worth arithmetic (i.e., levelization).
- **Fixed Charge Factor (FCF):** This parameter, also known as the *capital recovery factor*, is used to find the uniform annual amount needed to repay a loan or investment with interest. It is one of the most important parameters in the IECM. It determines the revenue required to finance the power plant based on the capital expenditures. Put another way, it is a levelized factor which accounts for the revenue per dollar of total plant cost that must be collected from customers in order to pay the carrying charges on that capital investment.
- **Inflation Rate:** This is the rise in price levels caused by an increase in the available currency and credit without a proportionate increase in available goods or services. It does not include real escalation.

### **CO₂ Transport System Retrofit Costs Inputs**

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	1	<u>Capital C</u>	ost Process A:	rea										
	2	Material Cost			retr	o \$/new \$		1.000		0.0	10.00	1.000		
	3	Labor Costs			retr	o \$/new \$		1.000		0.0	10.00	1.000		
	4	Right-of-way	Cost		retr	o \$/new \$		1.000		0.0	10.00	1.000		
	5	Booster Pump	Cost		retr	o \$/new \$		1.000		0.0	10.00	1.000		
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This screen is available for all plant types.

CO₂ Transport System – Retrofit Cost input screen.

### **Capital Cost Process Area**

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

The following are the **Capital Cost Process Areas** for the  $CO_2$  Transport System:

**Material Cost:** This includes the cost of line pipe, pipe coatings, and cathodic protection.

Labor Costs: This covers the cost of labor during pipeline construction.

**Right-of-way Cost:** This is the cost of obtaining right-of-way for the pipeline. This cost not only includes compensating landowners for signing easement agreements but landowners may be also be paid for loss of certain uses of the land during and after construction, loss of any other resources, and any damage to property.

Booster Pump Cost: This is the total capital cost of a booster pump.

**Miscellaneous Cost:** This includes the costs of: surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction (AUFDC), administration and overheads, and regulatory filing fees.

### CO₂ Transport System Capital Cost Inputs

This screen is available for all of the plant types; the **Combustion (Boiler)**, the **Combustion (Turbine)** and IGCC.

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		1	Construction Time		years		3.000		0.2500	10.00	3.000	
		2										
		3	General Facilities Capital		%PFC		0.0		0.0	50.00	0.0	
		4	Engineering & Home Office Fees		%PFC		0.0		0.0	50.00	0.0	
Ш		5	Project Contingency Cost		%PFC		0.0		0.0	100.0	0.0	
Ш		6	Process Contingency Cost		%PFC		0.0		0.0	100.0	0.0	
Ш		7	Royalty Fees		%PFC		0.0		0.0	10.00	0.0	
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Ш		10	Months of Fixed O&M		months		0.0		0.0	12.00	0.0	
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Ш		12	Misc. Capital Cost		%TPI		0.0		0.0	10.00	0.0	
Ш		13										
		14	Inventory Capital		%TPC		0.0		0.0	10.00	0.0	
		15										
		16										
		17										
		18	TCR Recovery Factor		%		100.0		0.0	200.0	100.0	
	I	Proc	ess Type: CO2 Transport		-							

CO₂ Transport System – Capital Cost input screen

Inputs for capital costs are entered on the Capital Cost input screen.

**Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

- **General Facilities Capital (GFC)**: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra

maintenance, and inefficient use of fuel or other materials during startup. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

- Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

### CO₂ Transport System O&M Cost Inputs

This screen is available for all plant types.

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<u>C</u> onfigure Plant	Set <u>P</u> a	rameters		<u>G</u> et Rest	ılts	
Overail Fuel Base Plant	t <u>M</u> ercury <u>N</u> Ox Control	<u>T</u> SP Control	SO2 Control	C <u>O</u> 2 Captus	re By-Pro Mgm	t S
Title	Units	Unc V	alue Calc	Min	Max	Default
1 Booster Pump Operating (	Cost %PFC	1	.500	0.0	100.0	1.500
2					0.010.01	
3 Fixed O&M Cost	\$/mile-yr	4	989	0.0	3.219e+04	4989
5						
6						
7						
8						
9						
10						
11						
12						
13						
15						
16						
17						
18						
Process Type: CO2 Transp	ort 👻	C	osts are in Cor	istant 200	5 dollars.	
		,		_		_

CO₂ Transport System – O&M Cost input screen.

Inputs for operation and maintenance are entered on the **O&M Cost** input. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below:

- **Booster Pump Operating Cost:** This is the cost of operating a booster pump as a percent of the process facilities capital
- **Fixed O&M Cost:** These are the operating and maintenance fixed costs including all maintenance materials and all labor costs and is given in dollars per mile of pipeline per year.

# CO₂ Transport System Diagram

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	Lak vew Go window Help		_ [_] X
	<u>C</u> onfigure Plant	Set <u>P</u> arameters	Get Results
	Overall Plant Fuel Air Separation	Gasifier <u>S</u> ulfur CO2 Area Removal <mark>Capture</mark>	Power <u>B</u> lock By-Prod. Stac <u>k</u>
	Pressure In (psia) 2000 CO2 Stream In (acfm) 80.32		Pressure Out (psia) 1688 CO2 Stream Out (acfm) 95.12
-	From Plant	No. of Booster Pumps 0.0	To Storage
		Ground Temperature (°F)         42.08           Pipe Segments         1.000           Pipe Size (inches)         14.00	
	Process Type: CO2 Transport		
	<u>1. Diagram 2. Gas</u>	🖌 <u>3</u> . Capital Cost 🖌 <u>4</u> . O&M Cost 💡	<u>5</u> . Total Cost

This screen is available for all plant types.

CO₂ Transport System – Diagram.

#### **From Plant**

- **Pressure In:** This is the pressure of the  $CO_2$  from the plant into the pipeline in absolute pounds per square inch.
- **CO₂ Stream In:** This is the flow of the CO₂ from the plant into the pipeline in actual cubic feet per minute.

#### To CO₂ Transport System

- **No. of Booster Pumps:** This is the number of booster pumps used (if any).
- **Ground Temperature:** Average ground temperature that the pipeline traverses.
- **Pipe Segments:** Total number of pipe segments from plant to injection site.

Pipe Size: Outer diameter of the pipe in inches.

### **To Storage**

- **Pressure Out:** This is the pressure of the CO₂ when it enters the storage site in absolute pounds per square inch.
- **CO₂ Stream Out:** This is the flow of the CO₂ from the pipeline into the storage site in actual cubic feet per minute.

### CO₂ Transport System Flue Gas Results

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.

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븱		0	lon	figure	e Plant	Ĩ	Se	t <u>P</u> aramete	rs	T	(	Get Results	_ لــــلك
	Overail Fuel Boiler Air NOx Plant Fuel Boiler Preheater Control							Mercury	<u>T</u> SP Control	<u>S</u> O Cont	2 C <u>O</u> 2 trol Captu	re By-Prod. Mgmt	Stac <u>k</u>
<i>≫</i> ∦ ₽					Major Flue	Gas Con		Flue Gas In (B-moles/hr)	Flue Gas (D-moles	Out /hr)	Flue Gas In (tons/hr)	Flue Gas Out (tons/hr)	
ß			1	Nitrog	gen (N2)			0.0	0.0		0.0	0.0	
el I			2	Oxyge	en (O2)			0.0	0.0		0.0	0.0	
			3	Water	r Vapor (H2C	))		0.0	0.0		0.0	0.0	
<b>-</b>			4	Carbo	n Dioxide (C	02)		1.843e+04	1.843e+	04	405.6	405.6	
•			5	Carbo	n Monoxide	(CO)		0.0	0.0		0.0	0.0	
<b>?</b>			6	Hydro	ochloric Aci	t (HCI)		5.358	5.358		9.768e-02	9.768e-02	
?			7	Sulfur	Dioxide (SC	2)		213.1	213.1		6.825	6.825	
<u>.                                    </u>			8	Sulfur	ic Acid (equ	ivalent S	03)	0.8592	0.8592	2	3.439e-02	3.439e-02	
			9	Nitric	Oxide (NO)			0.0	0.0		0.0	0.0	
			10	Nitrog	gen Dioxide (	NO2)		0.6790	0.6790	0	1.562e-02	1.562e-02	
			11	Ammo	onia (NH3)			0.0	0.0		0.0	0.0	
			12	Argor	n (Ar)			0.0	0.0		0.0	0.0	
			13	Total				1.865e+04	1.865e+	04	412.6	412.6	
			14										
			15										
	Pı	rocess [*] <u>1</u> . Dia	Type	: <mark>C(</mark>	02 Transpo <u>2</u> . F <u>lue</u>	ort Gas	💽 🤁 🖸	ost <u>4</u> .0	)&M Cost	6	<u>5</u> . Total Cost	t <u>6</u> .Cost	t Inputs

CO₂ Transport System – Flue Gas result screen

#### **Major Flue Gas Components**

Each result is described briefly below:

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCI): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

## CO₂ Transport System Gas Results

This screen is only available for the IGCC plant type.

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	ntitle	ed*									_ 🗆 ×
눼		C	onf	igure Pla	nt	Set	t <u>P</u> arameter	s		Get Results	
	Ove <u>r</u> all	Plant		Fuel	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac <u>k</u>
*				M	ajor Gas Compo	nents	Gas In (Ib-moles/hr)	Gas Out (b-moles/hr)	Gas In (tons/hr)	Gas Out (tons/hr)	
			1	Carbon Mo	noxide (CO)		0.0	0.0	0.0	0.0	
			2	Hydrogen (	H2)		0.0	0.0	0.0	0.0	
			3	Methane (C	H4)		0.0	0.0	0.0	0.0	
			4	Ethane (C2H	16)		0.0	0.0	0.0	0.0	
			5	Propane (C3	3H8)		0.0	0.0	0.0	0.0	
21			6	Hydrogen S	ulfide (H2S)		0.0	0.0	0.0	0.0	
<b>?</b>			7	Carbonyl Sı	ulfide (COS)		0.0	0.0	0.0	0.0	
			8	Ammonia (1	4H3)		0.0	0.0	0.0	0.0	
			9	Hydrochlor	ic Acid (HCI)		0.0	0.0	0.0	0.0	
			10	Carbon Dio	xide (CO2)		2.134e+04	2.134e+04	469.7	469.7	
			11	Water Vapo	rt (H2O)		0.0	0.0	0.0	0.0	
			12	Nitrogen (N	2)		0.0	0.0	0.0	0.0	
			13	Argon (Ar)			0.0	0.0	0.0	0.0	
			14	Oxygen (O2	)		0.0	0.0	0.0	0.0	
			15	Total			2.134e+04	2.134e+04	469.7	469.7	
	Proc	ess T	уре	CO2 Tr	ansport	▼ 2 Conitol C	art ( 4.0	Phil Coat /	5 Total Coa		
	<u> </u>	. Diag	gram		<u>2</u> . Gas	2. Capital Ci	JSt 🛕 4.04	zin Cost 👔	2. rotalCos	л /	

CO2 Transport System – Gas result screen

### **Major Gas Components**

Each result is described briefly below:

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H): Total mass of hydrogen.

Methane (CH₄): Total mass of methane.

Ethane (C₂H₆): Total mass of ethane.

Propane (C₃H₈): Total mass of propane.

Hydrogen Sulfide (H₂S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbon dioxide.

Ammonia (NH₃): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Water Vapor (H₂O): Total mass of water vapor.

Nitrogen (N₂): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O₂): Total mass of oxygen.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **CO₂ Transport System Capital Cost Results**

This screen is available for all plant types.

le <u>E</u>	M di	Inter t <u>V</u> ie	face w Go <u>W</u> indow <u>H</u> elp				
	F	Unti	<u>C</u> onfigure Plant	Set Par	ame	ters <u>G</u> et Ro	sults
	ſ	Ovej Plaz	all Fuel Boiler Air ht Fuel Boiler Preheater	NOx Control Mer	cury	TSP <u>S</u> O2 <u>CO</u> 2 Control Control Capture I	z-Prod. Mgmt Stac <u>k</u>
			CO2 Transport Process Area Cosis	Capital Cost (M\$)		CO2 Transport Plant Costs	Capital Cost (M\$)
		1	Material Cost	5.928	1	Process Facilities Capital	35.25
41		2	Labor Costs	18.11	2	General Facilities Capital	0.0
11		3	Right-of-way Cost	3.033	3	Eng. & Home Office Fees	0.0
111		4	Booster Pump Cost	0.0	4	Project Contingency Cost	0.0
Ш		5	Miscellaneous Costs	8.177	5	Process Contingency Cost	0.0
11		6	Process Facilities Capital	35.25	6	Interest Charges (AFUDC)	3.755
Ш		7			7	Royalty Fees	0.0
11		8			8	Preproduction (Startup) Cost	0.0
Ш		9			9	Inventory (Working) Capital	0.0
Ш		10			10	Total Capital Requirement (TCR)	39.00
1	1	11			11		
1	1	12			12		
Ш		13			13		
Ш		14			14	Filterative TCD	20.00
		Pro	cess Type: CO2 Transport	<b>•</b>	15	Costs are in Constant 2005 dollars.	39.00
	ľ		<u>1</u> . Diagram 🖌 <u>2</u> . Flue Gas <u>3</u>	.CapitalCost	4	. O&M Cost 🖌 🧕 Total Cost 🖌	

CO₂ Transport System – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

### CO₂ Transport Process Area Costs

- **Material Cost:** This includes the cost of line pipe, pipe coatings, and cathodic protection.
- Labor Costs: This covers the cost of labor during pipeline construction.
- **Right-of-way Cost:** This is the cost of obtaining right-of-way for the pipeline. This cost not only includes compensating landowners for signing easement agreements but landowners may be also be paid for loss of certain uses of the land during and after construction, loss of any other resources, and any damage to property.

**Booster Pump Cost:** This is the total capital cost of a booster pump.

**Miscellaneous Cost:** This includes the costs of: surveying, engineering, supervision, contingencies, telecommunications equipment, freight,

taxes, allowances for funds used during construction (AUFDC), administration and overheads, and regulatory filing fees.

**Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

#### CO₂ Transport Plant Costs

Process Facilities Capital: (see definition above).

- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the pipeline transport system that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

### CO₂ Transport System O&M Cost Results

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6	ſ		<u>C</u> onfigure Plant	Ĩ	Set <u>P</u> ar	ame	ters	<u>G</u> et Res	ults	1
		Ovej Plan	all Fuel Boiler P	<u>A</u> ir reheater	NOx Control Mer	cury	<u>T</u> SP <u>S</u> O2 Control Control	C <u>O</u> 2 Capture M	Prod. gmt Stac <u>k</u>	
 			Variable Cost Compon	ent	O&M Cost (M\$/yr)		Fixed Cost Cor	nponent	O&M Cost (M\$/yr)	
C.		1	Booster Pump Operating Cost		0.0	1	Total Fixed Costs		0.3100	
r B		2	Total Variable Costs		0.0	2				
		3				3				
		4				4				
-2		5				5				
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		0				0				
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		11				11				
		12				12				
		13				13				
		14				14				
		15				15	Total O&M Costs		0.3100	
		Pre	cess Type: CO2 Transport		•		Costs are in Constan	t 2005 dollars.		
			<u>1</u> . Diagram 🔏 <u>2</u> . Flue Ga	s <u>{ 3</u>	Capital Cost	4	O&M Cost <u>5</u> . To	otalCost /		

This screen is available for all plant types.

CO₂ Transport System – O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **CO₂ Capture** technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

#### **Variable Cost Components**

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

**Booster Pump Operating Cost:** This is the total capital cost of a booster pump.

**Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

#### **Fixed Cost Components**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

### CO₂ Transport System Total Cost Results

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		<u>C</u> onfigure Plant	Ĩ	Set <u>P</u> ar	ame	ters	<u>G</u> et Res	ults
		Overall Fuel Boiler Pre	<u>A</u> ir heater	NOx Control Mer	cury	<u>T</u> SP <u>S</u> O2 Control Control	CO2 Capture Mg	rod. mt Stac <u>k</u>
A X A		Variable Cost Componen	t	O&M Cost (M\$/yr)		Fixed Cost Com	ponent	O&M Cost (M\$/yr)
B		1 Booster Pump Operating Cost		0.0	1	Total Fixed Costs		0.3100
đ		2 Total Variable Costs		0.0	2			
		3			3			
		4			4			
		5			5			
2		7			7			
?		8			8			
		9			9			
		10			10			
		11			11			
		12			12			
		13			13			
		14			14	Tatal O &M Casta		0.2100
		Process Type: CO2 Transport		<b>_</b>	15	Costs are in Constant	2005 dollars.	0.3100
		<u>1</u> . Diagram <u>2</u> . Flue Gas	<u> </u>	.CapitalCost	4	O&M Cost <u>5</u> . Tot	alCost /	

This screen is available for all plant types.

CO₂ Transport System – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the  $CO_2$  **Transport System CO_2 Control** technology. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.
- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# Stack

### **Stack Diagram**



Stack - Diagram.

The **Diagram** result screen displays an icon for the stack and values for major flows out of it. Each result is described briefly below.

#### Flue Gas Out

**Temperature Out:** Temperature of the flue gas exiting the stack.

Flue Gas Out: Volumetric flow rate of flue gas exiting the stack, based on the flue gas temperature exiting the stack and atmospheric pressure.

Fly Ash Out: Mass flow rate of solids in the flue gas exiting the stack.

#### **Flue Gas Emission**

CO₂: This is the number of pounds of CO₂ vented to the air for every MBtu.

- **Equivalent SO₂:** This is the number of pounds of **Equivalent SO₂** vented to the air for every MBtu.
- **Equivalent NO₂ :**This is the number of pounds of **Equivalent NO₂** vented to the air for every MBtu.
- **Particulate:** This is the number of pounds of **Particulate** vented to the air for every MBtu.

#### **Mercury Emission**

- **Elemental:** This is the number of pounds of **Elemental Mercury** vented to the air for every MBtu.
- **Oxidized:** This is the number of pounds of **Oxidized Mercury** vented to the air for every MBtu.
- **Total:** This is the number of pounds of **Total Mercury** vented to the air for every MBtu.

#### **Mercury Exiting Stack**

- **Elemental Mercury:** Mass flow rate of elemental mercury (Hg⁰) in the flue gas exiting the stack.
- **Oxidized Mercury:** Mass flow rate of oxidized mercury (Hg⁺²) in the flue gas exiting the stack.
- **Total Mercury:** Mass flow rate of total mercury in the flue gas exiting the stack (elemental, oxidized, and particulate).

### **Stack Flue Gas Results**

The **FlueGas** result screen displays a table of quantities of flue gas components exiting the stack. For each component, quantities are given in both moles and mass per hour.

ľ		Configure Pl	ant		Set Pars	meters	Ĩ	Get De	eulte			
ŀ					500 <u>1</u> al 2			<u>O</u> et Ke	suits			
	Ove <u>r</u> all	Plant Fuel	<u>A</u> ir Separation	Gasii Are	fier <u>S</u> uli a Remo	er Surtur CO2 Capture Power Block Mg						
		Major Flue	e Gas Сонфонен	ts	By-Product Area (lb-moles/hr)	Power Block Area (Ib-moles/hr)	Total Flue Gas (Ib-moles/hr)	By-Product Area (ton/hr)	Power Block Area (ton/hr)			
I	1	Nitrogen (N2)			846.0	1.665e+05	1.674e+05	11.85	2332			
II	2	Oxygen (O2)			0.0	2.889e+04	2.889e+04	0.0	462.3			
II	3	Water Vapor (H2C	))		449.2	3.089e+04	3.134e+04	4.047	278.3			
II	4	Carbon Dioxide (C	:02)		793.0	2.159e+04	2.238e+04	17.45	475.0			
II	5	Carbon Monoxide	(CO)		0.0	0.0	0.0	0.0	0.0			
II	6	Hydrochloric Acid (HCl)		0.0	0.0	0.0	0.0	0.0				
I	7	Sulfur Dioxide (SC	)2)	0.3	0.3484	9.418	9.767	1.116e-02	0.3017			
II	8	Sulfuric Acid (equ	sivalent SO3)		0.0	0.0	0.0	0.0	0.0			
II	9	Nitric Oxide (NO)			1.786e-02	2.123	2.141	2.679e-04	3.186e-02			
II	10	Nitrogen Dioxide (	(NO2)		9.399e-04	0.1117	0.1127	2.162e-05	2.571e-03			
I	11	Ammonia (NH3)			0.0	0.0	0.0	0.0	0.0			
II	12	Argon (Ar)			0.0	412.2	412.2	0.0	8.233			
I	13	Total			2089	2.483e+05	2.504e+05	33.36	3556			
II	14											
I	15											
Ш									<u> </u>			

Stack Flue Gas result screen.

#### **Major Flue Gas Components**

Each result is described briefly below

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon(Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

### **Stack Emission Taxes Results**

😻 IE File	CN EQ	<b>1 Interface</b> lit <u>V</u> iew <u>W</u> indow	Help								
Ы	ļ	Untitled*									
0		<u>C</u> onfig	gure Pla	nt		Se	t <u>P</u> aramete	ers	Ĩ	<u>G</u> et Results	;
		Overall Plant	Fuel	<u>A</u> i Separa	r ition	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capt	ture Power H	By-Prod. Mgmt	Stac <u>k</u>
*						Tax on	Emissions		Cost (M\$/yr)		
ß				1	Su	ılfur Dioxide (SO2)	)		0.0	1	
P				2	Nit Co	trogen Oxide (equ whom Diovide (CO	iv. NO2) 2)		0.0	-	
2				4	To	ntal Emission Taxe	2) S		0.0		
<b>?</b>				5							
				6	i						
				7						-	
				0						-	
				1	D					-	
				1	1						
				1:	2						
				1:	3					-	
				1:	5					-	
		Process Type:	Stack					Costs ar	e in Constant	t 2000 dollars.	
		<u>1</u> . Diagram	<u> </u>	. Flue Ga	15	<u>3</u> . Emis. Ta	tes /				

Stack – Emis. Taxes result screen

The **Stack Emis. Taxes** results screen shows the cost of to the plant for emissions. The **Taxes on Emissions** are entered by the user in dollars per ton.

#### **Tax on Emissions**

- **Sulfur Dioxide (SO₂):** The cost (as a result of user entered data) to the plant of emitting sulfur dioxide in dollars per ton.
- Nitrogen Oxide (equiv. NO₂): The cost (as a result of user entered data) to the plant of emitting nitrogen oxide in dollars per ton.
- **Carbon Dioxide (CO₂):** The cost (as a result of user entered data) to the plant of emitting carbon dioxide in dollars per ton.
- **Total Emission Taxes:** This is the sum of the emission taxes displayed above. It is highlighted in yellow.

# **Power Block**

The power block technology area includes all the equipment necessary to convert the potential and kinetic energy of natural gas or syngas fuels into steam and electricity.

The process equipment is divided into several areas: the gas turbine/generator, the air compressor, the combustor, the steam turbine, and the heat recovery steam generator. These are all available in the **Combustion (Turbine)** and **IGCC** plant types.

### **Power Block Gas Turbine Inputs**

	C	onfigure Plant	s	et Param	ete	rs	Ĩ	<u>G</u> et Results			
Ove <u>r</u> a	11 Plan	t Fuel <u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Remova	, )	C <u>O</u> 2 Captu	re Po	wer <u>B</u> lock	By-Prod. Mgmt St		
		Title	Uni	its U	nc	Value	Calc	Min	Max	Default	
	1	<u>Gas Turbine/Generator</u>									
	2	Gas Turbine Model				GE 7FA 💌		Menu	Menu	GE 7FA	
	3	No. of Gas Turbines	inte	ger	1	2 🔽		Menu	Menu	2	
	4	Total Gas Turbine Output	M	7/		403.8	V	0.0	5000	calc	
	5	Fuel Gas Moisture Content	vol	%		33.00		0.0	100.0	calc	
	6	Turbine Inlet Temperature	°I	7		2420	V	2000	2500	calc	
	7	Turbine Back Pressure	ps	ia		2.000		0.0	10.00	2.000	
	8	Adiabatic Turbine Efficiency	%			95.00		0.0	100.0	95.00	
	9	Shaft/Generator Efficiency	%			98.00		0.0	100.0	98.00	
	10	<u>Air Compressor</u>									
	11	Pressure Ratio (outlet/inlet)	rat	io		15.70		1.000	25.00	15.70	
	12	A diabatic Compressor Efficienc	у %	)		70.00		0.0	100.0	70.00	
	13	Combustor									
	14	Combustor Inlet Pressure	ps	ia		294.0		0.0	350.0	294.0	
	15	Combustor Pressure Drop	ps	ia		4.000		0.0	10.00	4.000	
	16	Excess Air For Combustor	% sto	oich.		182.2	V	0.0	400.0	calc	
	17										
	10										

This screen is only available for the Combustion (Turbine) and IGCC plant types.

Power Block – Gas Turbine input screen.

#### **Gas Turbine/Generator**

**Gas Turbine Model:** This is a selection of the type of turbine model used (manufacturer types currently include only the "7FA"). The type

determines the inlet temperature, pressure ratio, and size parameters. This parameter list will be expanded in future versions.

- **No. of Gas Turbines:** This is the number of gas turbines. Since each turbine is able to produce a fixed output, the number of turbines will determine the plant size (e.g., gross plant size).
- **Total Gas Turbine Output:** This parameter is provided for reference purposes only. It provides the gross power generated from the gas turbines alone.
- **Fuel Gas Moisture Content:** Steam is typically added to the fuel gas prior to being combusted. This increases the volume of the fuel gas and results in a higher power output in the gas turbine.
- **Turbine Inlet Temperature:** The turbine inlet temperature is carefully controlled to prevent damage or fatigue of the first stage stator and rotor blades. This temperature is one of the two most important parameters that impacts system efficiency.
- **Turbine Back Pressure:** The turbine exit pressure must be higher than atmospheric pressure to provide a positive pressure on the flue gas exiting the turbine.
- Adiabatic Turbine Efficiency: The adiabatic turbine efficiency adjusts for inefficiencies in real turbines. The ratio is an estimate of real to ideal performance.
- **Shaft/Generator Efficiency:** The combined shaft/generator efficiency adjusts for inefficiencies in generator and shaft between the compressor and the generator. The ratio is an estimate of real to ideal performance.

#### Air Compressor

- **Pressure Ratio (outlet/inlet):** This is the ratio of the compressor exit pressure to the inlet ambient air pressure. Compression takes place approximately adiabatically.
- Adiabatic Compressor Efficiency: The adiabatic compressor efficiency adjusts for inefficiencies in real compressors. The ratio is an estimate of real to ideal performance.

#### Combustor

- **Combustor Inlet Pressure:** The combustor inlet pressure is currently fixed at a single value. It is provided for reference purposes only.
- **Combustor Pressure Drop:** Although the combustor operates at essentially constant pressure, a small pressure drop is typically observed in the combustor exit from the compressor exit.
- **Excess Air For Combustor:** This is the excess theoretical air used for combustion. It is added to the stoichiometric air requirement calculated by the model. This value is based on the required mass flow rate of syngas through the combustor, the heat content of the syngas, and the flame temperature of the combustor.

### **Power Block Steam Cycle Inputs**

📲 Untr	tle	d*				_			
	<u>C</u>	onfigure Plant	Set Par	amete	rs			Get Rest	ults
Ove <u>r</u> all l	Plan	t F <u>u</u> el Power <u>B</u> lock	Ox Control CO2	Capture	B <u>y</u> -Prod. Mgmt		Stac <u>k</u>		
		Title	Units	Unc	Value	Calc	Min	Max	Default
	1	Heat Recovery Steam Generator							
1	2	HRSG Outlet Temperature	°F		250.0		150.0	500.0	250.0
1	3	Steam Cycle Heat Rate, HHV	Btu/kWh		9000		6000	1.100e+04	9000
<u> </u>	4								_
	5	Steam Turbine							_
1	6	Total Steam Turbine Output	MWg		183.3	1	0.0	2000	calc
_	7								
	8	Power Block Totals	~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~	-				45.00	
	9.	Power Requirement	% MWg		2.000		0.0	15.00	caic
	10								
	11								
	12								_
	14					+			
	15								
	16			+					
	17								
1	18								

This screen is only available for the Combustion (Turbine) and IGCC plant types.

Power Block – Steam Cycle input screen

#### **Heat Recovery Steam Generator**

**HRSG Outlet Temperature:** This is the desired output temperature from the heat recovery steam generator (HRSG).

**Steam Cycle Heat Rate, HHV:** This is the steam cycle heat rate for the heat recovery steam generator.

#### **Steam Turbine**

**Total Steam Turbine Output:** This is the net electricity produced by the steam turbine associated with the HRSG (steam cycle). This value cannot be edited. It is provided for reference only.

#### **Power Block Totals**

**Power Requirement:** This is the electricity for internal use. It is expressed as a percent of the gross plant capacity.

## **Power Block Emission Factors**

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0		<u>C</u> onfigure Pla	nt 🍸	S	et <u>P</u> ara	met	ers	Ĩ		<u>G</u> et Res	ults	
	Ove <u>r</u> all Pl	ant F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulf Remo	ur val	C <u>O</u> 2 Captu	re Po	wer <u>B</u> lock	B <u>y</u> -Prod Mgmt	l. Sta	c <u>k</u>
8		Ti	itle	Uni	its	Unc	Value	Calc	Min	Max	Default	
*	1	Percent SOx as S	D3	vol	%		0.0		0.0	10.00	0.0	
<b>B</b>	2	NOx Emission Co	ncentration	ppı	nv		9.000		0.0	100.0	9.000	
	3	Percent NOx as N	i0	vol	%		95.00		90.00	100.0	95.00	
	4	Percent Total Car	bon as CO	vol	%		0.0		0.0	100.0	0.0	
	5											
←∭	6											
→ II	7											
<u>_</u>	8											
<u>.</u>	y 10											
		2										
	13	1										
	14	1										
	15	5										
	16	5										
	17	7										
	18	3										
	Pro	cess Type: Pow	er Block		-							
	<u>1</u> . Ga	s Turbine 🖌 <u>2</u> .3	Steam Cycle 🍦	<u>3</u> . Emis. Fa	ctors	<u>4</u> . F	etrofit Cost		i. Capital Co	ost 🖌 🤅	<u>6</u> . O&M Cos	t

Power Block – Emission Factors input screen.

#### **Emission Factors Input Parameters**

- **Percent SO_x as SO₃:** This is the volume percent of SO_x that is SO₃. The remainder is SO₂.
- $NO_x$  Emission Concentration: This is the concentration of  $NO_x$  emitted from the gas turbine after combustion.
- **Percent NO_x as NO:** This is the volume percent of  $NO_x$  that is NO. The remainder is  $NO_2$ .
- **Percent Total Carbon as CO:** This is the volume percent of the total carbon in the syngas entering the combustor that is emitted from the gas turbine as CO.

### **Power Block Retrofit Cost**

IEC Ie <u>E</u>	C <mark>M Interface</mark> Edit <u>V</u> iew Go <u>W</u> indow <u>H</u> elp							1	-   🗆
٦I	🚟 Untitled*								×
5	<u>C</u> onfigure Plant	Set <u>P</u> a	ramet	ers	Ì		<u>G</u> et Res	sults	
	Overall Plant Fuel <u>Air</u> Separation	Gasifier <u>S</u> i Area Rei	ilfur noval	CO2 Captu	rePo	wer <u>B</u> lock	By-Prod Mgmt	l. Stac <u>k</u>	
	Title	Units	Unc	Value	Calc	Min	Max	Default	1
11	1 Capital Cost Process Area								
111	2 Gas Turbine	retro \$/new \$		1.000		0.0	10.00	1.000	
111	3 Heat Recovery Steam Generator	retro \$/new \$		1.000		0.0	10.00	1.000	
	4 Steam Turbine	retro \$/new \$		1.000		0.0	10.00	1.000	
Ш	5 HRSG Feedwater System	retro \$/new \$		1.000		0.0	10.00	1.000	
11	6								
111	7								
11	8								
	9								
	10								
Ш	11								
Ш	12								
Ш	13								
Ш	14								
Ш	15		_						
Ш	16		_						
Ш	17		_						
	18								
	Process Type: Power Block	v.							
	<u>1</u> . Gas Turbine / <u>2</u> . Steam Cycle /	<u>3</u> . Emis. Factors	<u>4</u> . F	etrofit Cost		. Capital Co	ost /	<u>6</u> . O&M Cost	7

Power Block – Retrofit Cost input screen.

#### **Power Block Retrofit Cost Input Parameters**

- **Gas Turbine:** The Gas Turbine retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.
- **Heat Recovery Steam Generator:** The Heat Recovery Steam Generator retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.
- **Steam Turbine:** The Steam Turbine retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.
- **HRSG Feedwater System:** The Boiler Feedwater retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.

### **Power Block Capital Cost Inputs**

	C <mark>M Interfac</mark> e Edit <u>V</u> iew (	e Go <u>W</u> indow <u>H</u> elp										
	re Untitled'	<u>C</u> onfigure Pla	nt	Se	t <u>P</u> ara	mete	rs	Ţ		<u>G</u> et Res	sults	_ 🗆 ×
	Ove <u>r</u> all Pla	nt F <u>u</u> el	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulf Remo	ur val	C <u>O</u> 2 Captu	rePo	wer <u>B</u> lock	By-Prod Mgmt	l. Sta	ac <u>k</u>
		Ti	itle	Unit	s	Unc	Value	Calc	Min	Max	Default	
íII.	1	Construction Tim	le	year	s		4.000	V	0.2500	10.00	calc	
	2											
I	3	General Facilities	Capital	%PF	C		15.00		0.0	50.00	15.00	
	4	Engineering & H	ome Office Fees	%PF	C		10.00		0.0	50.00	10.00	
l	5	Project Continger	ncy Cost	%PF	C		15.00		0.0	100.0	15.00	
I	6	Process Continge	ency Cost	%PF	C		8.016		0.0	100.0	calc	
Ш	7	Royalty Fees		%PF	C		0.5000		0.0	10.00	0.5000	
	8											
Ш	9	Pre-Produ	ction Costs									
L	10	Months of Fixed	0&M	monti	ns		1.000		0.0	12.00	1.000	
I	11	Months of Variab	le O&M	monti	ns		1.000		0.0	12.00	1.000	
Ш	12	Misc. Capital Cos	ət 🛛	%TF	Ί		2.000		0.0	10.00	2.000	
I	13											
1	14	Inventory Capital		%TP	c		0.5000		0.0	10.00	0.5000	
1	15											
1	16											
	17											
	18	TCR Recovery Fa	ictor	%			100.0		0.0	200.0	100.0	
	Proc	ess Type: Pow	er Block		7							
	<u>1</u> . Gas	Turbine $\sqrt{2}$ .	Steam Cycle 🖌	<u>3</u> . Emis. Fac	tors /	<u>4</u> . R	etrofit Cost		<u>Σ</u> . Capital Co	ost	<u>6</u> . O&M Co	st /

Power Block – Capital Cost input screen.

Inputs for capital costs are entered on the Capital Cost input screen.

- **Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).
- **General Facilities Capital (GFC)**: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.
- **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.
- **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.
- **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an areaby-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable

O&M costs are described below with the addition of a miscellaneous capital cost factor.

- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.
- **TCR Recovery Factor:** The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

### **Power Block O&M Cost Inputs**

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ľ		<u>(</u>	<u>C</u> onfigure Plant	Ĩ	S	t <u>P</u> ar	amete	rs	Ĩ	<u>G</u> et Results			
	01	ve <u>r</u> all Pla	nt F <u>u</u> el <u>A</u> ir Separatio	n	Gasifier Area	<u>S</u> u Ren	ilfur noval	C <u>O</u> 2 Captı	are Po	wer <u>B</u> lock	By-Prod Mgmt	l. Sta	ıc <u>k</u>
	IГ		Title		Uni	is	Unc	Value	Calc	Min	Max	Default	
		1	Electricity Price (Base Plant)		\$/M\	Wh		61.06		0.0	200.0	calc	
I		2				1.10		0.070			20.00	0.070	
I		3	Number of Operating Jobs		jobs/s	hift	_	6.670		0.0	30.00	6.670	
I		4	Operating Labor Bate		\$/h	uay r		24.82		0.0	10.00	24.82	
I		6	-F			-		LINCL					
I		7	Total Maintenance Cost		%TI	с		1.500	V	0.0	10.00	calc	
I		8	Maint. Cost Allocated to Lab	or	% to	tal		40.00		0.0	100.0	40.00	
I		9	Administrative & Support Co	st	% total	labor		30.00		0.0	100.0	30.00	
		10											
		11											
		12											
I		14											
I		15							-				
I		16											
I		17											
I		18											
		Proc	ess Type: Power Block			Y		Costs are	e in Cor	istant 2005	dollars.		
I	K	<u>1</u> . Gas	Turbine 🖌 🙎 Steam Cycle		3. Emis. Fa	tors	<u>4</u> .R	etrofit Cost		. Capital Co	ost	6. O&M Cos	st

This screen is only available for the Combustion (Turbine) and IGCC plant types.

Power Block – O&M Cost input screen.

Inputs for operating and maintenance costs are entered on the **O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are

provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

- **Electricity Price (Base Plant):** This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is the power block. This is provided for reference purposes only.
- **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.
- Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)
- **Operating Labor Rate:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.
- **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.
- Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.
- Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

### **Power Block Gas Turbine Diagram**



Power Block – Gas Turbine Diagram result screen.

### **Air Entering Compressor**

- **Temperature In:** Temperature of the atmospheric air entering the air compressor.
- Air In: Volumetric flow rate of the air entering the air compressor.

### **Syngas Entering Combustor**

- **Temperature In:** Temperature of the syngas entering the fuel heater and saturator.
- **Pressure In:** This is the pressure of the synas as it enters the fuel heater and saturator.
- **Syngas In:** This is the mass flow rate of the syngas to the fuel heater and saturator.

#### Heated Syngas Entering Combustor

- **Temperature In:** Temperature of the heated and saturated syngas entering the combustor.
- **Pressure In:** This is the pressure of the heated and saturated syngas as it enters the combustor.
- **Syngas In:** This is the mass flow rate of the heated and saturated syngas to the combustor.

#### Flue Gas Exiting Gas Turbine

**Temperature Out:** Temperature of the flue gas exiting the gas turbine.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the gas turbine.

### **Power Block Steam Diagram**

V IEC	<b>M Interface</b> (dit <u>Vi</u> ew Go <u>Wi</u> ndow <u>H</u> elp		
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	<u>C</u> onfigure Plant	Set Parameters Get Results	
	Overall Plant Fuel <u>Air</u> Separation	n Gasifier Sulfur CQ2 Capture Fower Elock By-Prod. Star Area Removal CQ2 Capture Fower Elock Mgmt Star	: <u>k</u>
	Temperature Out (°F) 250.0 Flue Gas Out (tons/hr) 3431		
	Temperature In (°F) 1119 Flue Gas In (tons/hr) 3431		
	Process Type: Power Block	Y	
	1. GT Diagram 🔪 2. ST Diagram 🔏 💈	3. Syngas 🖌 4. Flue Gas 🖌 5. Capital Cost 🖌 6. O&M Cost 🖌 7. Total Cos	st

Power Block – HRSG/ Steam Diagram results screen.

#### Flue Gas Exiting Steam Generator

**Temperature Out:** Temperature of the flue gas exiting the HRSG system. **Flue Gas Out:** Volumetric flow rate of the flue gas exiting the HRSG.

#### Flue Gas Entering Steam Generator

**Temperature In:** Temperature of the flue gas entering the HRSG. **Flue Gas In:** Volumetric flow rate of flue gas entering the HRSG.

# **Power Block Syngas Results**

Configure Plant Se			t <u>P</u> arameters		<u>G</u> et Results			
Overall Plant	verall Plant Fuel Air Separation Major Syngas Con		Gasifier Area	Sulfur Removal Syngas In (D-moles/hr)	CQ2 Capture Heated Syng as In (Ib-moles/hr)	Power <u>B</u> lock Syngas In (ton/hr)	By-Prod. Mgmt Heated Syngas In (ton/hr)	Sta
			<b>ponents</b>					
Ē	1 Carbon Mo	Carbon Monoxide (CO)			918.4	12.86	12.86	
Ī	2 Hydrogen (	Hydrogen (H2)			3.177e+04	32.09	32.09	
Ī	3 Methane (C	Methane (CH4)			135.2	1.084	1.084	
Ī	4 Ethane (C2B	Ethane (C2H6)			0.0	0.0	0.0	
Ī	5 Propane (C.	Propane (C3H8)			0.0	0.0	0.0	
Ī	6 Hydrogen S	Sulfide (H2S)		0.2785	0.2785	4.746e-03	4.746e-03	
	7 Carbonyl S	ulfide (COS)		9.484	9.484	0.2848	0.2848	
	8 Ammonia(I	Ammonia (NH3)			3.196	2.722e-02	2.722e-02	
	9 Hydrochlor	Hydrochloric Acid (HCl)			0.0	0.0	0.0	
	10 Carbon Dio	Carbon Dioxide (CO2)			2243	49.37	49.37	
	11 Water Vapo	Water Vapor (H2O)			1.766e+04	59.82	159.1	
	12 Nitrogen (N	Nitrogen (N2)			352.5	4.937	4.937	
	13 Argon (Ar)	Argon (Ar)			417.3	8.336	8.336	
	14 Oxygen (O2	0		0.0	0.0	0.0	0.0	
	15 Total			4.249e+04	5.351e+04	168.8	268.1	

Power Block – Syngas result screen.

#### **Major Syngas Components**

Carbon Monoxide (CO): Flow rate of carbon monoxide in the syngas.
Hydrogen (H₂): Flow rate of hydrogen in the syngas.
Methane (CH₄): Flow rate of methane in the syngas.
Ethane (C₂H₆): Flow rate of ethane in the syngas.

**Propane (C₃H₈):** Flow rate of propane in the syngas.

Hydrogen Sulfide (H₂S): Flow rate of hydrogen sulfide in the syngas.

Carbonyl Sulfide (COS): Flow rate of carbon sulfide in the syngas.

Ammonia (NH₃): Flow rate of ammonia in the syngas.

Hydrochloric Acid (HCl): Flow rate of hydrochloric acid in the syngas.

**Carbon Dioxide (CO₂):** Flow rate of carbon dioxide in the syngas.

Water Vapor (H₂O): Flow rate of water vapor in the syngas.

Nitrogen (N₂): Flow rate of nitrogen in the syngas.

Argon (Ar): Flow rate of argon in the syngas.

**Oxygen (O₂):** Flow rate of oxygen in the syngas.

Total: Total flow rate of the syngas.

### **Power Block Flue Gas Results**
<u>C</u> 01	nfigure Plant	) Se	t <u>P</u> arameter	rs Ì		<u>G</u> et Results
verall Plant	Fuel Power Block	<u>N</u> Ox Control	C <u>O</u> 2 Capture	By-Prod. <u>M</u> gmt	Stac <u>k</u>	
	Major Flue Gas Co	nqonents	Air In (B-moles/hr)	Flue Gas Out (B-moles/hr)	Air In (ton/hr)	Flue Gas Out (ton/hr)
1	Nitrogen (N2)		9.505e+04	9.505e+04	1331	1331
2	Oxygen (O2)		2.528e+04	1.623e+04	404.5	259.6
3	Water Vapor (H2O)		0.0	9055	0.0	81.58
4	Carbon Dioxide (CO2)		0.0	4527	0.0	99.63
5	Carbon Monoxide (CO)		0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)		0.0	0.0	0.0	0.0
7	Sulfur Dioxide (SO2)		0.0	0.0	0.0	0.0
8	Sulfuric Acid (equivalent)	503)	0.0	0.0	0.0	0.0
9	Nitric Oxide (NO)		0.0	0.0	0.0	0.0
10	Nitrogen Dioxide (NO2)		0.0	0.0	0.0	0.0
11	Ammonia (NH3)		0.0	0.0	0.0	0.0
12	Argon (Ar)		0.0	0.0	0.0	0.0
13	Total		1.203e+05	1.249e+05	1736	1772
14						
15	5		]			

Power Block – Flue Gas results screen.

## **Major Flue Gas Components**

Each result is described briefly below:

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCI): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

**Total:** Total of the individual components listed above. This item is highlighted in yellow.

# **Power Block Capital Cost Results**

This screen is only available for the Combustion (Turbine) and IGCC plant types.

1	Configure Plant	Se	t Par	ame	ters	G	et Decu	lte
P			с <u>т</u> аг	ame	Y Y		et Kesu	TTS T
	Overall Plant Fuel Separation	Area	Ren	itur ioval	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stack
							[	
	Power Block Process Area Costs	Capital (M\$	Cost )		Power B	lock Plant Costs		Capital Cost (M\$)
	1 Gas Turbine	109.	6	1	Process Facilities	Capital		201.3
	2 Heat Recovery Steam Generator	34.5	5	2	General Facilities	Capital		30.19
I	3 Steam Turbine	51.4	9	3	Eng. & Home Off	ice Fees		20.13
I	4 HRSG Feedwater System	5.61	0	4	Project Continge:	ncy Cost		30.19
I	5			5	Process Conting	ency Cost		16.13
I	6			6	Interest Charges	(AFUDC)		49.27
I	7			7	Royalty Fees			1.006
I	8			8	Preproduction (S	tartup) Cost		4.668
I	9			9	Inventory (Work	ing) Capital		1.490
I	10			10	Total Capital Rec	uirement (TCR)		354.4
I	11 Process Facilities Capital	201.	3	11				
I	12			12				
I	13			13				
I	14			14				
I	15			15	Effective TCR			354.4
I	Program Transi	_			Costs are in (	"overtext 2005 dol	llane	

Power Block – Capital Cost results screen.

This result screen displays tables containing the **Power Block Capital Costs**. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

#### **Power Block Process Area Costs**

- **Gas Turbine:** The capital cost of the gas turbines, the air compressor, and the combustor.
- **Heat Recovery Steam Generator:**The heat recovery steam generator is a set of heat exchangers in which heat is removed from the gas turbine exhaust gas to generate steam for the steam turbine.
- **Steam Turbine:** The cost of a steam turbine is depends on the mass flow rate of steam through the turbine, the pressures in each stage, and the generator output.
- **HRSG Feedwater System:** The boiler feedwater system consists of equipment for handling raw water and polished water in the steam cycle, including a water mineralization unit for raw water, a dimineralized water storage tank, a condensate water, a condensate polishing unit, and a blowdown flash drum.
- **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

#### **Power Block Plant Costs**

Process Facilities Capital: (see definition above)

- **General Facilities Capital:** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.
- **Eng. & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.
- **Project Contingency Cost:** Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.
- **Process Contingency Cost:** Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.
- **Interest Charges (AFUDC):** Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.
- **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.
- **Preproduction (Startup) Cost:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.
- **Inventory (Working) Capital:** The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.
- **Total Capital Requirement (TCR):** Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.
- **Effective TCR:** The TCR of the power block that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

# **Power Block O&M Cost Results**

This screen is only available for the Combustion (Turbine) and IGCC plant types.

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5	ſ		Co	nfigure Pla	nt	Í	Se	et <u>P</u> ar	ame	ters		<u>G</u> et Resu	ılts	Ĩ
	Ove <u>r</u> all Plant F <u>u</u> el <u>A</u> ir G Separation				Ga A	isifier Area	<u>S</u> u Ren	lfur 10val	CO2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	nd. Stac <u>k</u>		
				Variable Cos	t Component		O&M (M\$/;	Cost yr)		Fixed	Cost Componen	t	O&M Cost (M\$/yr)	
5		1	Utility F	ower Credit			-34.4	4	1	Operating Labor			1.636	
я		2	Total V	ariable Costs			-34.4	4	2	Maintenance Lat	bor		1.788	
:11		3							3	Maintenance Ma	aterial		2.681	
411		4							4	Admin. & Suppo	ort Labor		1.027	Ш
20		5							5	Total Fixed Cost	ទ		7.131	Ш
111		6							6					Ш
111		7	_						7					
'		8	_						8					
		9	_					_	9					
		10	_					_	10					
		11						_	11					
		12						-	12					
		13	-					-	14					
		15						-	15	Total O&M Cos	ts		-27.31	
		Pr	ocess Ty	pe: Power	Block		Y			Costs are in	Constant 2005	dollars.		
	l	<u>1</u> .	GT Diagr	am 🖌 <u>2</u> . ST I	)iagram 🖌 🔮	. Syng	jas 🖌	<u>4</u> . Fh	ie Gas	<u>5</u> . Capital C	ost 📐 <u>6</u> . O&N	A Cost	7. Total Cost	Ζ

Power Block – O&M Cost results screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

#### Variable Cost Component

- Utility Power Credit: Power consumed by abatement technologies result in lower net power produced and lost revenue. The IECM charges each technology for the internal use of electricity and treats the charge as a credit for the base plant. When comparing individual components of the plant, these utility charges are taken into consideration. For total plant costs they balance out and have no net effect on the plant O&M costs.
- **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

#### **Fixed Cost Component**

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

- **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eighthour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.
- **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.
- **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

- Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
- **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
- **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

## **Power Block Total Cost Results**

This screen is only available for the Combustion (Turbine) and IGCC plant types.

<mark>♥</mark> IE <u>F</u> ile	IECM Interface											
ы	Intitled"											
	Γ	<u>C</u> ont	figure Pl	ant	;	S	et <u>P</u> aramete	rs		<u>G</u> et Results		
		Ove <u>r</u> all Plant	F <u>u</u> el	Ĩ	<u>A</u> ir Separation	Gasifier Area	<u>S</u> ulfur Removal	C <u>O</u> 2 Capture	Power <u>B</u> lock	By-Prod. Mgmt	Stac <u>k</u>	
*						Cost Compon	ent	M\$/yr	\$/MWh			
B	I			1	Annual Fix	ed Cost		7.131	2.452			
P	I			2	Annual Var	riable Cost		-34.44	-11.84			
	I			3	Total Annu	al O&M Cost		-27.31	-9.389	_		
	I			4	Annualized	Capital Cost		52.44	18.03			
	I			5	Total Level	ized Annual Co	st	25.13	8.641	_		
?	I			6						-		
N?	I			7						-		
_	I			8						-		
	I			9						-		
	I			11						-		
	I			12						-		
	I			13						-		
	I			14						-		
	I			15						-		
		Process Type	Powe	r Bl	ock	V	]	Costs are in (	Constant 2005	dollars.		
		<u>1</u> . GT Diagran	a <u>2</u> .ST	Dia	gram / į	3. Syngas 🖌	4. Flue Gas	<u>∫ 5</u> . Capital C	ost / <u>6</u> .0&N	A Cost <u>7</u> . T	otalCost	

Power Block – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

#### **Cost Component**

- **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
- **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
- **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

- **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.
- **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

# Units

# **Units Inputs**

Inputs may be entered using different units. Changing the units in which inputs are entered using the **Input Tools** floating palette is described in *Getting Started*. This section will describe the various unit settings in detail



The Input Tools Floating Palette

#### **Unit System**

The **Unit System** option determines the unit system in which input values are entered. The choices are **English** and **Metric**. The default setting is **English**.

# **Units Results**

Results may be displayed in different units. Changing the units in which results are displayed using the **Result Tools** floating palette is described in *Getting Started*. This section will describe the various unit settings in detail.

Result Tools: Untitle	d	×
Result Type:	Deterministic	•
	<u>Units</u>	
Unit System:	English	•
Time Period:	Default	•
Perf. Table:	Default	•
Cost Table:	M\$(Cap), M\$/yr(O&M)	-
	Revenue	
Cost Year:	1996	•
Inflation Ctrl:	Constant	•

The Result Tools floating palette

## **Result Type**

The **Result Type** option determines the type of values displayed in the result tables. The choices available are **Deterministic**, **Mean**, **Median** (50th percentile), 2.5 percentile, 97.5 percentile, and **Standard Deviation**. The default setting is **Deterministic**.

### **Unit System**

The **Unit System** option determines the unit system in which result values are displayed. The choices available are **English** and **Metric**. The default setting is **English**.

## **Time Period**

The **Time Period** option determines the time period for which result values are displayed. The choices available are **Default**, **Max Hourly** and **Annual Avg.** The default setting is **Default**.

## **Performance Table**

The **Perf. Table** option determines the units in which values are displayed on performance result screens. The choices available are **Default**, % **Total**, **mass/kWh**, and **mass/Btu in**. The default setting is **Default**.

NOTE: The **% Total** unit change can be used to determine the volume percent and weight percent of the components of the flue gas. This is possible when viewing the "Gas Summary" result table for any control technology.

## **Cost Table**

The **Cost Table** option determines the units in which values are displayed on cost result screens. The choices available are **M**\$(**Cap**), **M**\$/yr(**O**&**M**) and \$/kW(**Cap**), **mills/kWh**(**O**&**M**). The default setting is **M**\$(**Cap**), **M**\$/yr(**O**&**M**).

## Cost Year

The **Cost Year** option determines the year for which values are displayed on cost result screens. You may choose any year between 1977 and 1998. The default setting is **1996**.

## **Inflation Control**

The **Inflation Ctrl** option determines the method by which inflation is calculated for cost result screens. The choices available are **Constant** and **Current**. The default setting is **Constant**.

# **Working with Graphs**

## **Graph Chooser**

The table and diagram results displayed on the **Get Results** screens are all deterministic values; that is, uncertainties are not taken into consideration. Probabilistic results (with uncertainties taken into consideration) can be displayed in graphical format as a supplement to every deterministic value shown.

The graph chooser window opens when any value displayed on a result screen is double-clicked. The figure below shows the initial graph window.

Graph Session C	hooser	×
<u>G</u> raph Type:	Line (2D)	Difference
<u>X</u> Axis:	TSP Control Revenue Required (Selected Variable)	Choose
<u>¥</u> Axis:	Cumulative Probability	Choose
$\underline{Z}$ Axis:	×	Choose
<u>S</u> essions (a graj	ph may have 1-6 lines):	
		Add
		Dejete
		<u>U</u> р
		Do <u>w</u> n
<u>O</u> k	Cancel	

The graph chooser window

The graph chooser window contains several drop-down menus, a check box, and a few buttons. Each menu begins in a default state, producing a cumulative probability distribution (CDF) graph of the particular result variable double-clicked. These drop-down menus can be modified to produce many different types of graphs. These will be described in the following sections.

To view the standard CDF graph, select the menu items as they appear in the figure above:

- Graph Type: Line (2D)
- X Axis: (Selected Variable)
- Y Axis: Cumulative Probability

The graph type and details that will be displayed can be modified later if the initial graph is not what was desired.

## **Graph Type**



Graph type selection menu

The **Graph Type** drop-down menu contains multiple types of graphs. **Line (2D)** and **Scatter (2D)** can be selected initially with the line graph as the default option. Additional options are available after the graph opens. The line graph connects the x-y data points consecutively with line segments. The scatter graph displays the x-y data points with markers instead of line segments. Because the IECM generates sorted x-y data with x values always increasing, the two graphs will appear very similar. The only difference is the use of line segments and data markers.

### X Axis



X Axis variable selection menu

The **X** Axis drop-down menu allows you to select the independent variable. The menu initially contains only one item – the variable you double-clicked. This is the "selected variable" as shown in the figure above. If the **Choose** button immediately to the right of the drop-down menu is clicked, any input or result variable that exists in the IECM can be selected (see <u>Variable Chooser</u> on page 395).

#### Y Axis



YAxis variable selection menu

The **Y** Axis drop-down menu allows you to select the dependent variable. The menu initially contains only two items – "Cumulative Probability" and the variable you double-clicked. The second item is the "selected variable" as shown in the figure above. "Cumulative Probability" is the default option. If the **Choose** button immediately to the right of the drop-down menu is clicked, any input or result variable that exists in the IECM can be selected (see Variable Chooser).

#### Z Axis

Z Aoris:

Z Axis variable selection menu

The **Z** Axis drop-down menu allows you to select an additional variable. This option is currently unavailable.

-

### Variable Chooser



All the IECM variables are available through the **Choose** buttons.

Clicking the **Choose** button immediately to the right of the axis drop down menus in the graph chooser window opens the variable chooser window, as shown above. All the input variables listed in the IECM are included in this window. The variables are nested according to input or result variable, technology type, and technology suboption. These match the navigation tabs used in the IECM. Every variable is present in the same pattern as the IECM screens themselves.

Select a variable and click **Ok** to place the variable in the X-axis drop-down list. The variable chosen will be added to the drop down menu. For best results, select a variable that has a probabilistic function defined; in other words; the variable must be probabilistic in order to represent multiple values. Input variables in the IECM can be associated with uncertainty functions. Result variables must be a direct result of one or more input variables with uncertainty functions assigned. For more information on assigning uncertainty functions to input variables, see <u>Uncertainty Distributions</u>.

## **Selecting Multiple Sessions**

#### Sessions (a graph may have 1-6 lines):

Combustion CCS (user manual.idb)	Ado
Combustion Base (user manual.idb)	
	Deje
	Doy

Multiple session selection area

The graph chooser window allows the same variable(s) from multiple sessions to be displayed on the same graph. The sessions you may select to graph simultaneously are listed in the graph chooser window. The order of these can be changed by using

the **Up** and **Down** buttons on the right side of the window. Database files listed can be removed by using the **Delete** button on the right side of the window.

The default is to display only the variable(s) from the current session. As demonstrated in the figure above, only additional sessions are listed in the white area. All graphs displayed will use the X, Y, and Z variables selected in the graph selection window.

Choose Session		×
Please choose up to 3 sessions:		OK
Session Databases:	Sessions:	
👌 empty_session_database.idb (d:\cmu\models\doe	ी⊒ Combustion Base	Cancel
📔 sessdb.idb (d:\cmu\models\doe\c\iecminf\sessdb\s	∩∃ Combustion CCS	
ባ user manual.idb (d:\cmu\docs\iecm\manuals\user\		
Open DB Close DB		

Choose session window

To add additional session to your graph, use the **Add** button immediately to the right of this area. A session chooser window will be displayed as shown in the figure above. Up to five additional sessions can be selected. The sessions may come from multiple session database files. For more information on session databases, see <u>Session Database Files</u>.

The sessions you add will be reflected in the graph chooser window. All those shown will be displayed in a graph when you click the **Ok** button on the graph chooser window.

## **Difference Graphs**

Graph Session C	hooser	×
<u>G</u> raph Type:	Line (2D)	Difference
<u>X</u> Axis:	Gross Electrical Output	Choose
<u>Y</u> Axis:	Cumulative Probability	Choose
$\underline{Z}$ Axis:	The second secon	Choose
<u>S</u> essions (a gra	h may have 1-6 lines):	
	Combustion CCS (user manual.idb)	Add
	Combustion Base (user manual.idb)	
		Delete
		Up
		Do <u>w</u> n
<u>O</u> k	Cancel	

The graph chooser window can be used to display the difference in a variable across multiple sessions

The graphing window can also display the difference between the currently selected variable and the same variable in one to five other sessions. The result is a unique method of examining differences between key results across different modeling sessions.

The first step to graphing difference graphs is the click the **Difference** check box at the top of the graph chooser window. The next step is to select other sessions to compare with the current session. This is described in <u>Selecting Multiple Sessions</u> on page 395. Finally, click the **Ok** button at the bottom of the graph chooser window.

## **Graph Window**



Graph window using all default conditions

The graph window is a very powerful and versatile tool for viewing data results. The variables selected earlier are represented on the axes. Graph option buttons are provided above the graph, allowing you to change the appearance and style of the variables being graphed. These are described in a separate help document distributed with the IECM.





Graph controls can be accessed from any button on the graph window, or any tab from within the graph control window itself. The two methods are synonymous.

Each button at the top of the graph window opens the same graph control window, but with a particular tab selected. The figure above shows the row of buttons in the graph window and the graph control window that opens when one of the buttons is clicked. Consult the graphing help file for more detailed descriptions of the graph option buttons. The graphing help file is distributed with the IECM software and is accessible from the graph control window (see the help button on the lower right of the figure above).

NOTE: Right-clicking the graph window will also open the graph control window.

# **Importing and Exporting Graphs**

If a graph window is active, you may use the Windows copy function (press **Ctrl-C**) to copy the graph to the clipboard. Both the data and the graph will be placed on the clipboard at the same time.

Because the clipboard contains both data and graph information, it is not certain in which format Windows will paste the graph into an application. Windows may paste a Bitmap image, a Windows Metafile image, or a data list of x-y values taken from the graph. By default, graphics programs will typically paste the graph information and word processing programs will paste the data information. To determine how the graph will be pasted, use the **Paste <u>As</u>** function in your target application to paste the graph.

Graph Control	Overlav Error Bar Background Legend							
2D Gallery 3D Gallery Style Data Titles Axis 3D Fonts								
Labels	System About							
Printing	Export Image							
Border	Image Format: WMF							
<u> M</u> ono ■	Compression:							
O <u>C</u> olor	Image Target:							
Landscape	O Clipboard Browse							
Eull page	• <u>F</u> ile:							
Print	Сору							
Export Map File	Graph Template							
Eormat Client	Save Data Browse							
Tag	File							
Ref Strings	Browse Name							
File	Load Save							
ОК Са	ncel Apply Now Help							

The "System" tab in the graph control window allows data to be imported and saved in any method.

Full control of importing and exporting is accomplished through the "System" tab in the graph control window, as shown in the figure above. For more detailed information, please consult the graph window help file.

# **Graph Window Help**



Detailed Help File Window

Detailed graph help is available by clicking the **?** button on the graph window. Clicking this button brings up the help file as shown in the figure above. This detailed help is not reproduced here.

# **Running a Probabilistic Analysis**

# **Uncertainty Analysis**

As noted in the introduction, a unique feature of the IECM is its ability to analyze uncertainties probabilistically. You may assign probability distributions to any input parameter, including calculated parameters. The combined effect of all uncertain parameters is then calculated. This chapter describes again how to specify input probability distributions, and how to set several additional parameters needed to conduct a probabilistic analysis.

Even after probabilistic values have been set you do *not* have to use them. Probabilistic analysis can be turned on or off individually for technologies or input types or all at once. Turning the probabilistic calculations on and off for particular portions of the plant allows you to evaluate the major sources of uncertainty.

# **Uncertainty Distributions**

The entry of uncertainty distributions is covered briefly in *Getting Started* This section gives a more detailed description of the process.

#### **Uncertainty Parameters**

Each uncertainty distribution requires one or more parameters. The table below lists the parameters and numerical value limits required for each distribution type.

Function	Operator	min or mean	mode	max or sdev
Normal, Half-	*	x >= 0	N/A	x > 0
normal(s)	+	х	N/A	x > 0
LogNormal	*	x > 0	N/A	x >= 1
	+	x > 0	N/A	x >= 1
Uniform	*	x >= 0	N/A	x >= 0
	+	х	N/A	х
Triangular	*	x >= 0	x >= 0	x >= 0
	+	х	х	х
Fractiles	*	x >= 0	N/A	N/A
	+	N/A	N/A	N/A

Wedge	*	x >= 0	N/A	x >= 0
	+	x	N/A	x

#### **Distribution Types**

Several types of probability distributions are provided with the IECM. Brief descriptions of each uncertainty distribution are included in the model when the uncertainty editor is selected; the information required, and additional notes, appear below. Distributions that are easiest to use are designated with a dagger (†). Consult a standard statistics reference for additional information.

#### None

None represents no uncertainty.

#### Normal Distributions

**†Normal** (**mean, stddev**) returns a continuous, normal Gaussian probability distribution with the specified **mean** and the standard deviation, **stddev**.

**†Neghalf_Normal** (**mean, stddev**) returns the lower half of a normal Gaussian probability distribution with the specified **mean** and the standard deviation, **stddev**.

**†Half_Normal** (**mean, stddev**) returns the upper half of a normal Gaussian probability distribution with the specified **mean** and the standard deviation, **stddev**.

This bell-shaped distribution is often assumed in statistical analysis as the basis for unbiased measurement errors. The normal distribution has infinite tails; however, over 99 percent of all values of the normal distribution lie within plus or minus three standard deviations of the mean. Thus, when used to represent uncertainty in physical quantities which much be greater than zero, the standard deviation should not be more than about 20 or 30 percent of the mean.

#### Lognormal Distribution

**Lognormal** (**median**, **gsdev**) returns a continuous lognormal probability distribution with the specified **median** and the geometric standard deviation, **gsdev**. The geometric standard deviation must be 1 or greater.

This distribution is usually used to represent uncertainty in physical quantities which must be positive values that are positively skewed, such as the ambient concentration of a pollutant. This distribution may be appropriate when uncertainties are expressed on a multiplicative order-of-magnitude basis (e.g., factor of 2) or when there is a probability of obtaining extreme large values.

#### **Uniform Distribution**

**†Uniform** (**min, max**) returns a continuous probability distribution in which every value between **min** and **max** has an equal chance of occurring.

Use this when you are able to specify a finite range of possible values, but are unable to decide which values in the range are more likely to occur than others. The use of the uniform distribution is also a signal that the details about uncertainty in the variable are not known. It is useful for screening studies.

#### Triangular Distribution

**†Triangular** (**min, mode, max**) returns a continuous, triangular probability distribution bounded by **min** and **max** and with the specified **mode**.

Use this when you are able to specify both a finite range of possible values and a "most likely" (mode) value. The triangle distribution may be symmetric or skewed. Like the uniform distribution, this distribution indicates that additional details about uncertainty are not yet known. The triangle distribution is excellent for screening studies.

#### Fractiles

**Fractiles**. If n is the number of elements in the list L, **Fractiles** (L) returns a continuous probability distribution where the first element is the 0% fractile, the second is the 1/(n-1) fractile, the third is the 2/(n-1) fractile, and so on. (The values must be enclosed in square-brackets to register as a "list.")

This distribution looks like a histogram for large sample sizes and can be used to represent any arbitrary data or judgment about uncertainties in a parameter, when the parameter is continuous. It explicitly shows detail of the uncertainties. It is used in the IECM Model to represent all trace species data in the default databases. The finite range of possible values is divided into subintervals. Within each subinterval, the values are sampled uniformly according to a specified frequency for each subinterval.

#### Wedge Distribution

**†Wedge** (**min, max**) returns a continuous wedge-shaped probability distribution increasing linearly from **min** to **max**.

Use this when you are able to specify a finite range of possible values. The wedge distribution increases linearly from zero probability at the minimum value to the maximum probability at the maximum value. Like the uniform distribution, this distribution indicates that additional details about uncertainty are not yet known. This is a special case of the triangular distribution described below.

# **Configuring Uncertainty in Results**

Some uncertainty parameters may be changed while results are displayed. These are modified using the Uncertainty Tools Floating Palette

Uncertainty Tools: Untitled							
Uncertainty Areas							
🔽 Bas	e Plant	🔽 NOx Control					
🔽 Air Preheater		🔽 Particulate Control					
🔽 Solid Waste Mgmt.		SO2 Control					
		SO2/NOx Control					
	Select All	Select None					
Graph Size: 50							
Sample	Size: 50						
Sampling Method: Median LHS							

The Uncertainty Tools floating palette

### **Uncertainty Areas**

You may choose technology or technologies for which you would like results with uncertain values by clicking the box to the left of each technology. You may select all or none by clicking the buttons at the bottom of the palette.

## Graph Size

The sample size determines the number of possible data points used to draw a graph. This parameter determines how many of the total samples to use for the graph. This value cannot exceed the sample size.

## Sample Size

You can also specify the number of samples used with the sampling method. This is the number of iterations performed in a probabilistic analysis. The appropriate sample size depends on the number and types of uncertainty distributions that are specified, and on the accuracy with which the distribution is to be estimated (especially the tails of the distribution). A sample size of 100 is the default. The maximum is 200. The calculation time and memory requirements are proportional to this value.

## **Sampling Methods**

Input and output variables are related to each other by model definitions defined for each variable. These relationships are generally referred to as the "decision tree." The model uses this decision tree to determine which input variables must be calculated to specify the output variable. Only those input variables necessary to specify the output variable value are calculated.

Since each input variable can be expressed as a non-singular distribution, a method of sampling the inputs must be determined. Several methods are available in the model, ranging from a deterministic or single "best guess" value to a completely random sampling of each input distribution. The sampling methods all produce sets of values for the inputs. These sets together form the "sampling space."

#### Deterministic Evaluation

Output values can be determined by using the most probable value for each input. This method is frequently referred to as the "best guess."

Input variables can be treated deterministically either by specifying only a single value, or by selecting the "Off" option for the "Uncertainty Distribution" pane. This option forces all uncertain parameters to be evaluated deterministically. Selecting the "Off" option forces each uncertainty function used in the decision tree to be evaluated using its expected value. This option overrides any particular uncertainty distribution types.

#### Monte Carlo

Monte Carlo is the simplest and best-known sampling method. It draws values at random from the uncertainty distribution of each input variable in the decision tree. For a particular sampling run, each input variable is randomly sampled once. The random samples from each input result in one final output value. This process is repeated *m* times and results in a final solution set. This set can then be evaluated with standard statistical techniques to determine the mean, precision, and confidence.

This method has the advantage of providing an easy method of determining the precision for a specific number of samples using standard statistical techniques. However, it suffers from requiring a large number of samples for a given precision. It also has the drawback of substantial noise in the resulting distribution. For these reasons, Latin Hypercube sampling is preferred as the model default.

#### Latin Hypercube

Latin Hypercube is a stratified sampling method that divides the sampling space into equally probable intervals, or strata. For each input variable, the method samples each interval in a random order. When the samples from each input variable are combined, one resultant output is determined. This process is repeated *m* times, forming a final result of *m* output values. These *m* output values contain the uncertainty of the output variable, based on all the uncertainties of the entire set of input variables. The value *m* is referred to as the sample size.

The model contains two variations of Latin Hypercube sampling: Random and Median. **Random Latin Hypercube** (RLH) samples each strata randomly, while the **Median Latin Hypercube** (MLH) samples each strata by its median value. (See: Diwekar, U.M. and J.R. Kalagnanam, (1997) "Efficient Sampling Technique for Optimization under Uncertainty," *AIChE Journal*, Vol. 43, No. 2, pp. 440-7.) Median Latin Hypercube is the default sampling method.

Both forms of Latin Hypercube have the advantage of sampling more uniformly over the input distributions relative to Monte Carlo sampling, resulting in less noise in the final distribution. Another advantage is the reduced number of samples that must be taken to satisfy a given precision. Latin Hypercube has the drawback that the precision is more difficult to calculate using statistical methods. Finally, the output is random but not independent.

#### Hammersley

A new sampling technique has been added to the IECM which is more efficient than either the Monte Carlo or Latin-Hypercube sampling techniques. It is called the Hammersley sequence sampling technique. (See: Diwekar, U.M. and J.R. Kalagnanam, (1997) "Efficient Sampling Technique for Optimization under Uncertainty," *AIChE Journal*, Vol. 43, No. 2, pp. 440-7.) The sampling method is loosely based on the Monte Carlo method. However, instead of using a random number generator, it uses a quasi-random number generator based on Hammersley points to uniformly sample a unit hypercube. These points are an optimal design for placing n points on a k-dimensional hypercube. The sample points are then inverted over a cumulative probability distribution to define the sample set for any uncertainty variable.

Hammersley has the advantage of high precision and consistent behavior in addition to better computational efficiency. The method reduces the number of samples required relative to the other sampling methods for calculating uncertainty by a factor of 2 to 100. The actual sample reduction varies with the uncertainty function being sampled.

# Appendix A - Introduction to Uncertainty Analysis

## **Uncertainty Analysis**

The following section is provided as a means of introducing uncertainty analysis as a tool for model design and operation. However, you should consult standard statistical and other texts (e.g., Morgan and Henrion, Uncertainty, Cambridge Press, 1990) to develop a more complete understanding of the subject.

## Introduction

Nearly all analyses of energy and environmental control technologies involve uncertainties. The most common approach to handling uncertainties is either to ignore them or to use simple sensitivity analysis. In sensitivity analysis, the value of one or a few model input parameters are varied, usually from low to high values, and the effect on a model output parameter is observed. Meanwhile, all other model parameters are held at their nominal values. In practical problems with many input variables which may be uncertain, the combinatorial explosion of possible sensitivity scenarios (e.g., one variable "high," another "low," and so on) becomes unmanageable. Furthermore, sensitivity analysis provides no insight into the *likelihood* of obtaining any particular result.

A more robust approach is incorporated in the IECM to represent uncertainties in model parameters using probability distributions. Using probabilistic simulation techniques, uncertainties in any number of model input parameters can be propagated through the model simultaneously to determine their combined effect on model outputs. The result of a probabilistic simulation includes both the possible range of values for model output parameters and information about the likelihood of obtaining various results. You may have seen probabilistic analysis referred to elsewhere as "range estimating" or "risk assessment."

The development of ranges and probability distributions for model input parameters can be based either on statistical data analysis and/or engineering judgments. The approaches to developing probability distributions for model parameters are similar in may ways to the approach you might take to pick a single "best guess" number for deterministic (point-estimate) analysis, or to select a range of values to use in sensitivity analysis.

# **Philosophy of Uncertainty Analysis**

The classical approach to probability theory requires that estimates for probability distributions be based on empirical data. However, in many practical cases, the available data may not be available or relevant to the problem at hand. Thus, statistical manipulation of data may be an insufficient basis for estimating uncertainty. Engineering analysis or judgments about the data may be required.

An alternative approach is the "Bayesian" view. It differs in how probability distributions are interpreted. The probability of an outcome is your "degree of belief" that the outcome will occur, based on all of the relevant information you currently have about the system. Thus, the probability distribution may be based on empirical data and/or other considerations, such as your own technically-informed judgments. The assessment of uncertainties requires thought about all possible outcomes and their likelihood, not just the "most likely" outcome. The advantage to thinking systematically and critically about uncertainties is the likelihood of anticipating otherwise overlooked problems, or identifying potential payoffs that might otherwise be overlooked.

# Types of Uncertain Quantities

There are a number of types of uncertainty to consider when developing a probability distribution for a variable. Some of these are summarized briefly here.

*Statistical error* is associated with imperfections in measurement techniques. Statistical analysis of test data is thus one method for developing a representation of uncertainty in a variable.

Empirical measurements also involve *systematic error*. The mean value of a quantity may not converge to the "true" mean value because of biases in measurement and procedures. Such biases may arise from imprecise calibration, faulty reading of meters, and inaccuracies in the assumptions used to infer the actual quantity of interest from the observed readings of other quantities. Estimating the possible magnitude of systematic error may involve an element of engineering judgment.

*Variability* can be represented as a probability distribution. Some quantities are variable over time. For example, the composition of a coal (or perhaps a sorbent) may vary over time.

Uncertainty may also arise due to lack of actual experience with a process. This type of uncertainty often cannot be treated statistically, because it requires predictions about something that has yet to be built or tested. This type of uncertainty can be represented using technical estimates about the range and likelihood of possible outcomes. These judgments may be based on a theoretical foundation or experience with analogous systems.

# **Encoding Uncertainties as Probability Distributions**

As indicated in the previous sections, there are two fundamental approaches for encoding uncertainty in terms of probability distributions. These include statistical estimation techniques and engineering judgments. A combination of both methods may be appropriate in many practical situations. For example, a statistical analysis of measured test data for a new emission control technology may be a starting point for thinking about uncertainties in a hypothetical commercial scale system. You must then consider the effect that systematic errors, variability, or uncertainties about scaling-up the process might have on interpreting test results for commercial-scale design applications.

#### **Statistical Techniques**

Statistical estimation techniques involve estimating probability distributions from available data. The fit of data to a particular probability distribution function can be evaluated using various statistical tests. For example, the cumulative probability distribution of a set of data may be plotted on "probability" paper. If the data plot as a straight line, then the distribution is normal. Procedures for fitting probability distribution functions are discussed in many standard texts on probability and are not reviewed here.

Such procedures can be utilized to obtain distribution functions for many of the power plant parameters in the IECM when data are available for operating plants. In other cases, especially where data are limited, expert technical judgments may be necessary to develop appropriate distribution functions for model parameters. The emphasis of the discussion below is on the situations where statistical analysis alone may be insufficient.

#### **Judgments about Uncertainties**

In making judgments about a probability distribution for a quantity, there are a number of approaches (heuristics) that people use which psychologists have observed. Some of these can lead to biases in the probability estimate. Three of the most common are briefly summarized.

- **Availability:** The probability experts assign to a particular possible outcome may be linked to the ease (availability) with which they can recall past instances of the outcome. For example, if tests have yielded high sorbent utilization, it may be easier to imagine obtaining a high sorbent utilization in the future than obtaining lower utilization. Thus, one tends to expect experts to be biased toward outcomes they have recently observed or can easily imagine, as opposed to other possible outcomes that have not been observed in tests.
- **Representativeness:** has also been termed the "law of small numbers." People may tend to assume that the behavior they observe in a small set of data must be representative of the behavior of the system, which may not be completely characterized until substantially more data are collected. Thus, one should be cautious in inferring patterns from data with a small number of samples.
- Anchoring and adjustment: involves using a natural starting point as the basis for making adjustments. For example, an expert might choose to start with a "best guess" value, which represents perhaps an average or most likely (modal) value, and then make adjustments to the best guess to achieve "worst" and "best" outcomes as bounds. The "worst" and "best" outcomes may be intended to represent a 90 percent probability range for the variable. However, the adjustment from the central "best guess" value to the extreme values is often insufficient, with the result that the probability distribution is too tight and biased toward the central value. This phenomenon is overconfidence, because the expert's judgment reflects less uncertainty in the variable than it should. The "anchor" can be any value, not just a central value. For example, if an expert begins with a "worst" case value, the entire distribution may be biased toward that value.

**Motivational Bias:** Judgments also may be biased for other reasons. One common concern is *motivational bias*. This bias may occur for reasons such as:

- a person may want to influence a decision to go a certain way;
- the person may perceive that they will be evaluated based on the outcome and might tend to be conservative in their estimates;
- the person may want to suppress uncertainty that they actually believe is present in order to appear knowledgeable or authoritative; and
- the expert has taken a strong stand in the past and does not want to appear to contradict himself by producing a distribution that lends credence to alternative views.

# **Designing an Elicitation Protocol**

Studies of uncertainty judgment show that the most frequent problem encountered is overconfidence. Knowledge of how people make judgments about probability distributions can be used to design a procedure for eliciting these judgments. The appropriate procedure depends on the background of the expert and the quantity for which the judgment is being elicited. For example, if you have some prior knowledge about the shape of the distribution for the quantity, then it may be appropriate to ask you to think about extreme values of the distribution and then to draw the distribution yourself. On the other hand, if you have little statistical background, it may be more appropriate to ask you a series of questions. For example, you might be asked the probability of obtaining a value less than or equal to some value x, and then the question is repeated for a few other values of x. Your judgment can then be graphed by an elicitor, who would review the results of the elicitation with you to see if you are comfortable with your answers.

To overcome the typical problem of overconfidence, consider extreme high or low values before asking about central values of the distribution. In general, experts' judgments about uncertainties tend to improve when:

- the expert is forced to consider how things could turn out differently than expected (e.g., high and low extremes); and
- the expert is asked to list reasons for obtaining various outcomes.

While the development of expert judgments may be flawed in some respects, it does permit a more robust analysis of uncertainties in a process when limited data are available. Furthermore, in many ways, the assessment of probability distributions is qualitatively no different than selecting single "best guess" values for use in a deterministic estimate. For example, a "best guess" value often represents a judgment about the single most likely value that one expects to obtain. The "best guess" value may be selected after considering several possible values. The types of heuristics and biases discussed above may play a similar role in selecting the value. Thus, even when only a single "best guess" number is used in an analysis, a seasoned engineer usually has at least a "sense" for "how good that number really is." This may be why engineers are usually able to make judgments about uncertainties, because they implicitly make these types of judgments routinely.

## A Non-technical Example

To illustrate the process of defining a subjective probability distribution, let's turn to a simple example of eating lunch in a cafeteria. How long does it take from the time you enter the cafeteria to the time you pay the cashier? Assume that you enter at 12:05 p.m. on a weekday and that you purchase your entire meal at the cafeteria. The answer you give may depend on your recent experiences in the cafeteria. Think about the shortest possible time that it could take (suppose nobody else is getting lunch) or the longest possible time (everyone shows up at the same time). What is the probability that it will take 2 minutes or less? 45 minutes or less? Is the probability that it takes 10 minutes or less greater than 50 percent? etc. After asking yourself a number of questions such as these, it should be possible to draw a distribution for your judgment regarding the time require to obtain and purchase lunch at the cafeteria. Such a distribution might take the form of a fractile distribution giving the probabilities of different waiting times to purchase lunch. For example, your evaluation may conclude that there is only a 1 percent (1 in 100) chance it will take one minute or less, a 60 percent chance of 1 to 10 minutes, a 25 percent likelihood of 10 to 15 minutes, and a 14 percent chance of up to 25 minutes. These probability intervals can be drawn as a histogram and translated into a fractile distribution for a probabilistic analysis.

## A Technical Example

A second example focuses on a performance parameter for an advanced pollution control system. This parameter has an important effect on system performance and cost.

The example focuses on an assessment of uncertainty in the performance of an innovative emission control system for coal-fired power plants. In this system, a chemical sorbent circulates between a fluidized bed reactor, where  $SO_2$  in the flue gas is removed by chemical reaction with the sorbent, and a regenerator, in which  $SO_2$  is evolved in a reaction of the sulfated sorbent with methane. There is no commercial experience with this system; the largest test unit has been sized to handle 100 scfm of flue gas. Furthermore, the test units have used batch, rather than continuous, regeneration.

One of the key parameters affecting the performance and cost of this system is the regeneration efficiency, which is defined as the fraction of the spent sorbent which is converted for reuse. In small-scale tests in which the regeneration efficiency has been estimated, the efficiency was found to be roughly 30 to 50 percent. In a more recent test, the regeneration efficiency was not measured due to instrumentation difficulties; however, it may have been lower than the previously obtained values. Regeneration residence times were typically greater than 30 minutes.

A detailed modeling study of the regenerator estimated that a properly sized and designed unit, coupled with heating of the sorbent to a sufficiently high reaction temperature, would result in a regeneration efficiency of just over 99 percent at a 30 minute residence time.

A potential problem that may be occurring in the test units is that regenerated sorbent in the regenerator may be reabsorbing some of the evolved  $SO_2$ . However, this was not considered in the modeling study of the regenerator.

Based on this information, it appears that it may be possible to achieve the design target of over 99 percent regeneration efficiency. Clearly, however, it is possible that the actual efficiency may be substantially less than this target value. As a worst case, we might consider the known test results as a lower bound. Thus, there is a small

chance the regeneration efficiency may be less than 50 percent. We expect the regeneration efficiency to tend toward the target value of 99.2 percent. Thus, to represent the expectation that the efficiency will be near the target value, but may be substantially less, we can use a negatively skewed distribution. In this case, we assume a triangle with a range from, say, 50 to 99.2 percent with a mode also at 99.2 percent. The triangle in this case gives us a distribution with a mean of about 83 percent and a median of about 85 percent. This type of triangular distribution, in which a minimum, maximum, and modal value are specified, is often a convenient way of expressing uncertainty distributions when a little information is available.

# **Appendix B - Technical Support**

# **Reaching Technical Support**

Questions, issues or concerns regarding the Integrated Environmental Control Model should be directed to:

#### **Carnegie Mellon University**

BERKENPAS, MICHAEL B. Office: Baker Hall 128B Location: Pittsburgh, PA 15213 Phone: (412) 268-1088 FAX: (412) 268-1089 Email: <u>mikeb@cmu.edu</u> Web: <u>www.iecm-online.com/support.html</u>

## National Energy Technology Laboratory

GROL, ERIC P.E. Office: Office of Systems, Analysis and Planning Location: Pittsburgh, PA 15236 Phone: (412) 386-5463 Email: <u>Eric.Grol@netl.doe.gov</u> Web: <u>www.netl.doe.gov</u>

Questions can also be directed through the IECM web site. The web site distributes the question to a team of engineers that will address your question and reply to you.

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