REINHOLD ENVIRONMENTAL Ltd.

2013 Coal to Gas Conversion Round Table & Expo Presentation

October 29, 2013, in Chattanooga, TN / Sponsored by Southern Company

Impact of Coal to Gas Conversion or Co-firing on Existing Air Quality Control Systems

Chris Wedig

Joe Jankauskas

Greg Fynan

Reinhold – Coal to Gas Round Table
October 29, 2013
Chattanooga, Tennessee

This presentation contains forward-looking statements regarding CB&I and represents our expectations and beliefs concerning future events. These forward-looking statements are intended to be covered by the safe harbor for forward-looking statements provided by the Private Securities Litigation Reform Act of 1995. Forward-looking statements involve known and unknown risks and uncertainties. When considering any statements that are predictive in nature, depend upon or refer to future events or conditions, or use or contain words, terms, phrases, or expressions such as “achieve,” “forecast,” “plan,” “propose,” “strategy,” “envision,” “hope,” “will,” “continue,” “potential,” “expect,” “believe,” “anticipate,” “project,” “estimate,” “predict,” “intend,” “should,” “could," “may,” “might,” or similar forward-looking statements, we refer you to the cautionary statements concerning risk factors and “Forward-Looking Statements” described under “Risk Factors” in Item 1A of our Annual Report filed on Form 10-K filed with the SEC for the year ended December 31, 2012, and any updates to those risk factors or “Forward-Looking Statements” included in our subsequent Quarterly Reports on Form 10-Q filed with the SEC, which cautionary statements are incorporated herein by reference.

- Introductions
- **FUELS** - Coal to gas conversion fuels
- **FLUE GAS** - Coal to gas conversion flue gas composition and properties
- **AQCS** – Examples of impacts of coal to gas conversion, supplemental firing or co-firing to existing air quality control systems (AQCS) of coal fired power plants (design and/or O&M)
- Summary
- Acknowledgements

Introduction

- Coal to gas conversion will result in changes to the flue gas composition/properties. Specific changes will depend on amount of gas fired and furnace/burner modifications.

- Coal to gas conversion can impact existing air quality control systems (AQCS) of coal fired power plants.

- In general, existing coal-fired AQCS technologies are compatible with flue gas from gas conversion (supplemental firing or co-firing), with AQCS design modifications and/or operation and maintenance (O&M) changes, as required.

Fuel Description

Natural Gas

Natural Gas Fuel Composition (pipeline)- examples

Component (% by volume)	Natural Gas - A	Natural Gas - B	Natural Gas - C	Natural Gas - D
Methane	94.1	85.00	93.33	96.6
Ethane	3.01	7.10	trace	1.78
Hydrogen	0.01	trace	1.82	0.002
Other Hydrocarbons	0.70	3.3	0.25	0.13
Carbon Monoxide	trace	trace	0.45	trace
Carbon Dioxide	0.71	0.60	0.22	0.44
Nitrogen	1.41	4.00	3.40	1.02
Oxygen	0.01	trace	0.35	trace
Trace Components	trace	trace	trace	trace

Note: the exact composition of pipeline quality natural gas can vary, but typically, the main component is methane (CH_4, usually 80 to 95% vol).

Delivered Generic Coal and Pipeline Gas Relative Comparison of Composition

Component (% by weight)	Generic Coal	Generic Natural Gas
Hydrogen	Base	Much More
Moisture	Base	Much Less
Ash	Base	Much Less
Oxygen	Base	Less
Carbon	Base	Similar
Sulfur	Base	Much Less
Nitrogen	Base	Similar
Halides (Cl, Br, F, I)	Base	Much Less
Trace Metals (Hg, As, Se, etc.)	Base	Much Less

There are different methods to process and handle natural gas and associated related products, as presented below.

- Offshore oil & gas production systems, including platform topsides and floating production, storage and offloading (FPSO) vessels
- Onshore oil & gas field production
- Onshore pipelines
- Natural gas processing
- LNG liquefaction plants and regasification terminals
- Bulk liquid storage structures for both atmospheric and low temperature/cryogenic storage

- Refinery process units
- Petrochemical facilities
- Gasification plants
- Hydrogen generating plants
- Sulfur processing plants
- Bulk liquid storage structures for both atmospheric
- and low temperature/cryogenic storage
- Licensed technologies and related catalysts for
- refining, petrochemical and gas processing
- Heat transfer equipment

- Natural gas liquefaction plants
- LNG regasification terminals
- LNG peak shaving facilities
- LNG storage tanks

Source: CB&I website

Pipeline Quality Natural Gas

The raw natural gas must be purified to meet the quality standards specified by the major pipeline transmission and distribution companies.

Those quality standards may vary slightly from pipeline to pipeline and are usually a function of a pipeline system's design and the markets that it serves.

Based on reference – Gas Research Institute (GRI-94/0243.2)

Trace Components of Pipeline Natural Gas - examples

- Be delivered at or above a specified hydrocarbon dew point temperature (below which some of the hydrocarbons in the gas might condense at pipeline pressure forming liquid slugs that could damage the pipeline). Dew-point adjustment serves the reduction of the concentration of water and heavy hydrocarbons in natural gas to such an extent that no condensation occurs during the ensuing transport in the pipelines.

- Be free of particulate solids and liquid water to prevent erosion, corrosion or other damage to the pipeline.

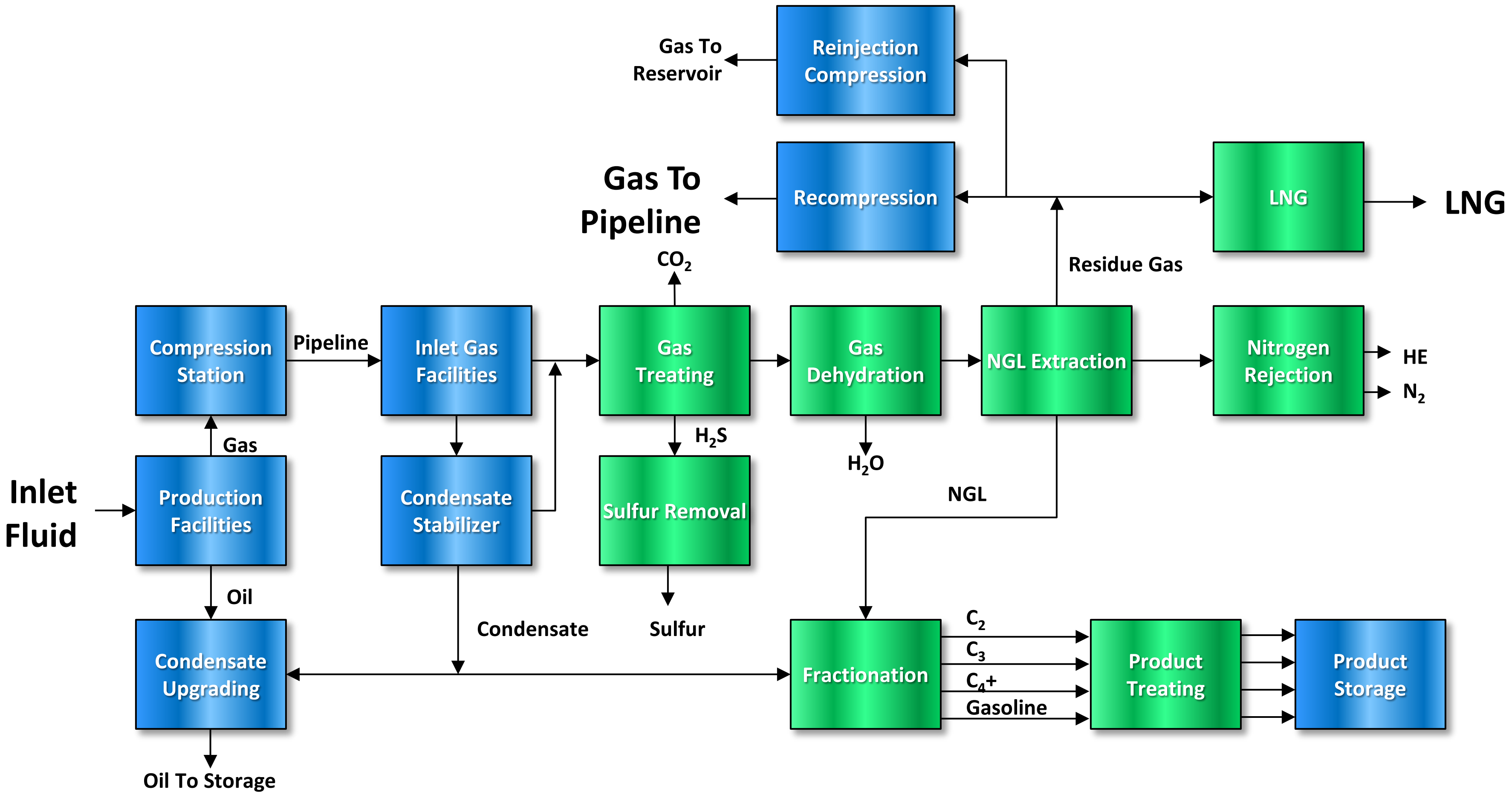
- Be dehydrated of water vapor sufficiently to prevent the formation of methane hydrates within the gas processing plant or subsequently within the sales gas transmission pipeline. A typical water content specification in the U.S. is that gas must contain no more than seven pounds of water per million standard cubic feet (MMSCF) of gas.

- Contain no more than trace amounts of components such as hydrogen sulfide and mercaptans. A common specification for hydrogen sulfide content is 0.25 grain H_2S per 100 cubic feet of gas, or approximately 4 ppm.

- Specifications for carbon dioxide (CO_2) typically limit the content to no more than two or three percent.

- Maintain mercury (Hg) at less than detectable limits (approximately 0.001 ppb by volume) primarily to avoid damaging equipment in the gas processing plant or the pipeline transmission system from mercury amalgamation and embrittlement of aluminum and other metals.

Based on reference - Natural-Gas Processing


Gas To Reservoir
Reinjection Compression
Gas To Pipeline
Recompression
LNG
LNG
CO2
Residue Gas
Compression Station
Pipeline
Inlet Gas Facilities
Gas Treating
Gas Dehydration
NGL Extraction
Nitrogen Rejection
HE
N2
Gas
H2S
H2O
Inlet Fluid
Production Facilities
Condensate Stabilizer
Sulfur Removal
NGL
Oil
Condensate
Sulfur
C2
C3
C4+
Gasoline
Condensate Upgrading
Fractionation
Product Treating
Product Storage
Oil To Storage

Analysis	% by Weight (ranges)
Carbon	64 to 76
Hydrogen	20 to 24
Nitrogen	0.7 to 13
Oxygen	1 to 2
Sulfur	trace
Moisture	trace
Ash	nil

Note: the composition of natural gas fuels can vary, but expressed on a weight basis, carbon and hydrogen represent the highest values.

Flue Gas Description

Natural Gas

- Coal to gas conversion (or co-firing) will result in **changes to the flue gas composition and distribution** entering the existing AQCS, such as, moisture, CO_2, NOx, ash, SO_2, SO_3, H_2SO4, HCl, HBr, HF, Hg, trace metals, CO/VOC, etc.

- Coal to gas conversion (or co-firing) may result in **changes to the flue gas physical properties and distribution** entering the existing AQCS, such as, temperature, flow rate, distribution, adiabatic saturation temperature (due to moisture content), molecular weight, etc.

- Specific change in flue gas composition & properties will depend on degree of natural gas firing, type of natural gas and coal used (Bit, PRB, lignite), excess air employed, and furnace modifications & specifics, etc.

The fundamental combustion equation for burning natural gas fuel is:

Eq 1) Natural Gas (fuel) + Oxygen (O_2 from air) → Carbon Dioxide (CO_2) + Moisture (H_2O)

There are a variety of chemical reactions during the combustion of natural gas with air including:

Eq 2) **$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$ + heat**

Eq 3) **$C_2H_6 + 3.5O_2 \rightarrow 2CO_2 + 3H_2O$ + heat**

Eq 4) **Natural Gas (other hydrocarbons) + $O_2 \rightarrow CO_2 + H_2O$ + heat**

Eq 5) **Natural Gas Hydrogen $2H_2 + O_2 \rightarrow 2H_2O$ + heat**

Eq 6) **Nitrogen (N_2 from air and NG) + O_2 → NOx ($NO + NO_2$)**

Eq 7) **Natural Gas (hydrocarbons) + $O_2 \rightarrow CO + H_2O$**

Eq 8) **Natural Gas (hydrocarbons) + O_2 → VOC + H_2O**

Eq 9) **Natural Gas (trace sulfur compounds) → SO_2 (trace) + H_2O**

Eq 10) Other chemical reactions (trace)

Higher Heating Values of Gaseous Fuels - examples

Gaseous Fuels	Higher Heating Value (HHV, Btu/lb)
Natural Gas – generic range	20,160 to 23,300
Methane (CH_4)	23,880
Ethane (C_2H_6)	22,329
Propane (C_3H_8)	21,670
Butane (C_4H_{10})	21,316
Ethylene (C_2H_4)	21,646
Acetylene (C_2H_2)	21,477
Hydrogen (H_2)	61,030
Carbon Monoxide (CO)	4,346

Source: Handbook of Chemical Engineering

Flue Gas Composition – Bulk Composition – Entering AQCS System (e.g. FGD)
Coal vs. Natural Gas - 100% Conditions - examples

Flue Gas Component (% by vol)	Coal – A1 PRB (example)	Coal – A2 Bituminous (example)	Coal – A3 Lignite (example)	Natural Gas A4 (example)	Natural Gas A5 (example)	Natural Gas A6 (example)
N_2	71.26	75.27	69.03	72.25	72.22	71.89
CO_2	12.08	10.76	11.07	7.04	6.85	7.55
O_2	5.28	7.31	6.09	5.47	5.44	4.39
H_2O	11.09	6.42	13.6	15.16	15.41	16.09
Ash	yes	yes	yes	Nil	Nil	Nil
NOx	yes	yes	yes	yes	yes	yes
CO	yes	yes	yes	yes	yes	yes
VOC	yes	yes	yes	yes	yes	yes
SO_2	yes	yes	yes	Nil	Nil	Nil
SO_3/H_2SO_4	yes	yes	yes	Nil	Nil	Nil
HCl/HF/HBr	yes	yes	yes	Trace	Trace	Trace
Trace Metals (Hg, Se, etc.)	yes	yes	yes	Trace	Trace	Trace

Coal vs. Natural Gas - Relative Comparison – examples

Flue Gas Component (% by volume)	Generic Coal Flue Gas Entering AQCS	Generic Natural Gas Flue Gas Entering AQCS
Nitrogen (N_2)	Base	Similar
Carbon Dioxide (CO_2)	Base	Less
Oxygen (O_2)	Base	Less or Similar
Moisture (H_2O)	Base	Higher
Ash	Base	Much Less
Nitrogen Oxides (NOx)	Base	Less or Similar
Carbon Monoxide (CO)	Base	Similar or Higher
Volatile Organic Compounds (VOC)	Base	Similar
Sulfur Dioxide (SO_2)	Base	Much Less
Sulfur Trioxide (SO_3/H_2SO_4)	Base	Much Less
Hydrogen Chloride (HCl)	Base	Much Less
Hydrogen Fluoride (HF)	Base	Much Less
Hydrogen Bromide (HBr)	Base	Much Less
Trace Metals (Hg, As, Se, etc.)	Base	Much Less

Flue Gas Adiabatic Saturation Temperature (AST) Values, within a flue gas desulfurization (FGD) system, for various coal and natural gas types, at full firing conditions (examples, showing potential influence of flue gas moisture content) [1]

Parameter	Coal – A1 PRB (example)	Coal – A2 Bituminous (example)	Coal – A3 Lignite (example)	Natural Gas A4 (example)	Natural Gas A5 (example)	Natural Gas A6 (example)
Adiabatic Saturation Temperature (FGDS, deg F)	**134**	**124**	**138**	**141**	**142**	**143**
Flue Gas Moisture (Inlet FGDS, % vol H_2O)	**11.09**	**6.42**	**13.6**	**15.16**	**15.41**	**16.09**
Flue Gas Molecular Weight (wet) (lb/lb-mole)	**29.16**	**29.57**	**28.81**	**27.95**	**27.90**	**27.89**

Note: 1) in addition to flue gas moisture content, the AQCS inlet flue gas inlet temperature and composition can impact the flue gas adiabatic saturation temperature (AST) values.

Air Quality Control Systems

Impacts of Coal to Gas Conversion (or co-firing) on Existing AQCS of Coal-Fired Power Plant

In general, existing coal-fired air quality control system (AQCS) equipment are compatible with the flue gas from gas conversion (supplemental firing or co-firing), with equipment design or BOP modifications, by-pass (if required), and/or operation and maintenance (O&M) changes as needed.

Even after a coal unit is converted to natural gas (supplemental firing or co-firing), certain realities such as regulations and boiler load following issues may still apply, depending on site specifics.

For example, if at a multiple unit station, one unit is converted to 100% natural gas, while the other units remain coal firing (or supplemental firing or co-firing), it is possible that certain regulations and load following issues may still exist.

- MATS
- Regional Haze
- Effluent limitation guidelines (WFGD WWTS, dry flyash and bottom ash conversions)
- Coal combustion residues (potential CCR, potential pond conversion to new landfills)
- Section 316 (a & b) (possible cooling water issues)
- Potential Green-house gas (GHG/CO_2) issues
- Consent Decree (if applicable)
- Other regulations (state or federal)

Boiler load following issues may apply even after a coal unit is converted to natural gas firing .

- Designing, operation, and maintaining coal-fired plant air quality control systems (AQCS) in compliance while accommodating more frequent ramp-up/ramp-downs (due to revised dispatch priority) may be a reality.
- This includes potentially more frequent unit shut-downs and start-ups plus revised unit ramp rates (MW-minute values) to accommodate electrical grid load following.
- Potential reasons why load following issues may apply even after a coal unit is converted to natural gas firing (or co-firing) include:
    - Revised Dispatch Priority (either due to internal or external reasons)
    - Electricity Pricing
    - Grid Load Demand
    - Age and/or Heat Rate of Existing Power Plant
    - Natural Gas Pricing vs. Coal Pricing
    - Renewables Dispatching to Grid (e.g. Wind, Solar, Bio-mass, etc.)
    - Newer Power Plants Connected to Grid (e.g. coal, NG-CC, NG-SC, nuclear)
    - Limits and Changes in Electrical Transmission to Grid (e.g. new corridors)
    - Environmental Issues
    - Other reasons or issues

For a coal to gas conversion (or supplemental firing or co-firing of natural gas) project, the disposition of the existing coal-fired power plant air quality control system (AQCS) equipment depends on the nature of the project and site specifics. Generic examples of possible dispositions scenarios for existing coal-fired AQCS are as follows.

- **Scenario A1** "re-fuel" - Full (100%) conversion to natural gas project (**retain ability to burn coal for the future**, if natural gas pricing increases), burn natural gas fuel in existing boiler with required modifications, by-pass AQCS that is not needed, de-energize AQCS not needed, keep any needed AQCS & Stack functional with modifications (if required), BOP.
- **Scenario A2** "re-fuel" - Full (100%) conversion to natural gas project (*permanently*, **no coal firing in the immediate future**), burn natural gas fuel in existing boiler with required modifications, permanent by-pass of AQCS that is not needed, *permanently* de-energize AQCS not needed, keep any needed AQCS & Stack functional with modifications (if required), BOP, etc.
- **Scenario B** "re-fuel" - Coal firing with supplemental or co-firing of natural gas (with **continued routine coal-firing**) in existing boiler with required modifications, keep needed AQCS & Stack functional with modifications (as required), BOP, etc.
- **Scenario C** "repowering" - Burn 100% natural gas, **repower** existing facility with natural gas-fired combustion turbine, natural gas in-duct firing (if required), and HRSG with CO/VOC catalyst & SCR, retire existing coal-fired boiler and AQCS, modify BOP as required.
- **Scenario D** – other disposition scenarios for existing coal-fired AQCS equipment.

Air Quality Control Systems minimize stack emissions:

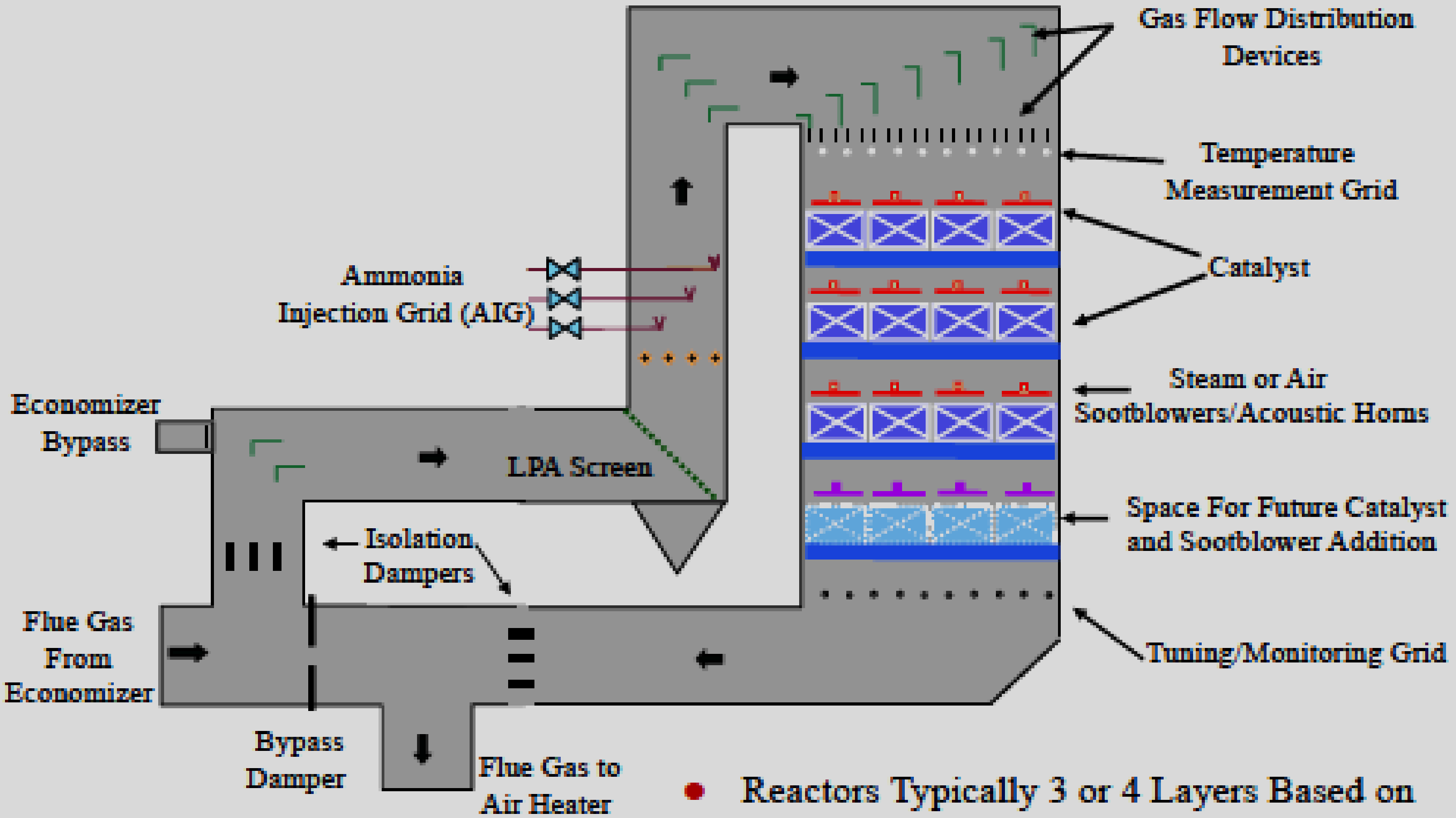
- Mercury (Hg)
- Hydrogen Chloride (HCl)
- Particulate Matter (filterable and condensable)
- Opacity (%)
- Sulfur Trioxide (SO_3)/Sulfuric Acid Mist (H_2SO_4)
- Hazardous Air Pollutants (HAPs)
- Sulfur Dioxide (SO_2)
- Nitrogen Oxides (NO_X)
- Carbon Monoxide (CO)
- Volatile Organic Compounds (VOC)
- Ammonia Slip (NH_3)
- Other

Nitrogen Oxides (NOx) Control

Nitrogen Oxides (NOx) Control

- Low NOx Burners (LNB)
- Over-fired Air (OFA, LNCFS, CCF, etc.)
- Burner Management (BOOS, burner upgrades, pulverizer upgrades, etc.)
- Combustion Optimization (including computer pattern recognition, network, PI, balancing CO/VOC/NOx/LOI issues, etc.)
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)
- Coal Fuel Blending (blend existing higher chloride/sulfur coals with PRB)
- Coal Fuel Switch (PRB)
- Gas Reburn (FLGR, etc.)
- Supplemental firing with Natural Gas
- Gas Conversion
- Flue Gas Recirculation (FGR)
- Other NOx control technologies

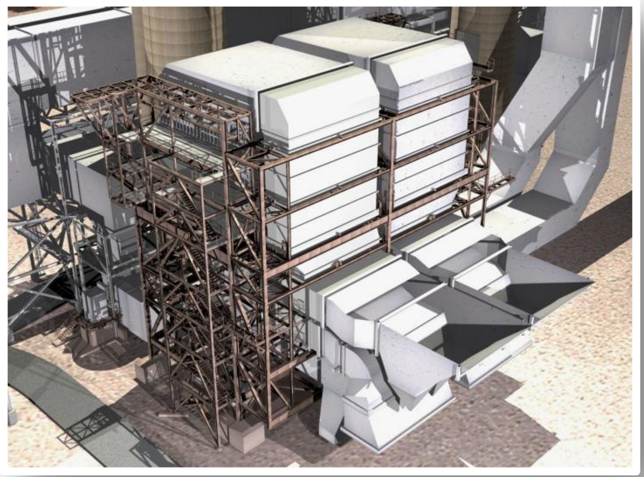
SCR System Reactor Arrangement (High Dust)



- Reactors Typically 3 or 4 Layers Based on Catalyst Deactivation Rate (Fuel Dependent)
- Need for Reactor and Economizer Bypass is a Project Specific Decision

CERAM ENVIRONMENTAL, INC.

- $4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$
- $NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O$
- $6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$
- $2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$



- **Low NOx burners (LNB modifications or new LNB for co-firing/full NG, combustion air modifications, along with furnace, fans & coal-pulverizers)**
  - modifications (or new) LNB/air systems to allow natural gas burning (as required), minimizing NOx production (e.g. thermal, prompt, and/or coal fuel)
- **Selective non-catalytic reduction (SNCR)**
  - possible changes in furnace flue gas temperature profile & flow rate
  - decreased urea feed rate
  - other impacts
- **Selective catalytic reduction (SCR)**
  - possible changes in inlet flue gas NOx levels
  - possible changes in inlet flue gas temp profile and flow rate & distribution
  - possible changes in SCR MOT
  - possible changes in NH_4HSO_4 deposition and sublimation issues
  - decreased NH_3 feed rate
  - investigate possible changes in SCR NH_3 slip
  - decreased SO_3 formation
  - investigate potential impacts on SCR catalyst management
  - investigate potential changes in Hg speciation and SCR Hg oxidation
  - possible decreased pop-corn ash & PFA buildup on SCR catalyst
  - other impacts

Particulate Matter (PM) Control

Particulate Matter (PM) Control

- Electrostatic Precipitator (CS ESP, HS ESP, FGC, ADA, ESP upgrades, HFTR, etc.)
- Fabric Filter (PJFF, RAFF, ESP to FF conversion, FF upgrades, new bag material)
- WFGD Upgrades (to improve PM emissions)
- Wet Electrostatic Precipitator (WESP)
- Coal Fuel Blending
- Gas-Reburn (FLGR, etc.)
- Supplemental firing with Natural Gas
- Gas Conversion
- Other PM control technologies

An existing ESP can be modeled to provide rough estimates of particulate emissions during co-firing of coal with natural gas. For example, various tools are available including sophisticated computer models combined with CFD for detailed results and/or use of fundamental mathematical equations to predict rough trends. The following is a pre-conceptual study example, which can be followed-up by a detailed analysis of the ESP.

The modified Deutsch-Anderson equation is based on a theoretical concept that flyash is collected logarithmically along the length of an electrostatic precipitator (ESP), and that the efficiency of an ESP can be described roughly by the following equation "A".

Eq. A $Eff = 1 - \exp(-wA/Q)^m$

where

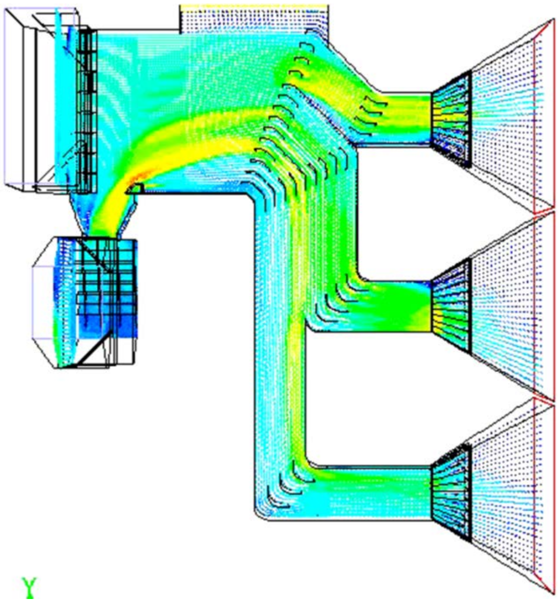
- **Eff = the efficiency of flyash collection in an ESP, % flyash removed.**
- **exp = exponential (e = base of natural logarithm = 2.718)**
- **w = migration velocity of the flyash (ft/sec)**
- **A = effective collecting plate area of the ESP, ft^2**
- **Q = flue gas flow rate through the ESP, actual cubic feet per second**
- **m = exponent modification parameter (numerical factor)**
- **Note: A/Q → [=] SCA (specific collection area of an ESP), ft^2 per 1000 acfm**

Eq. B $Eff = (In - Out)/In$

Where

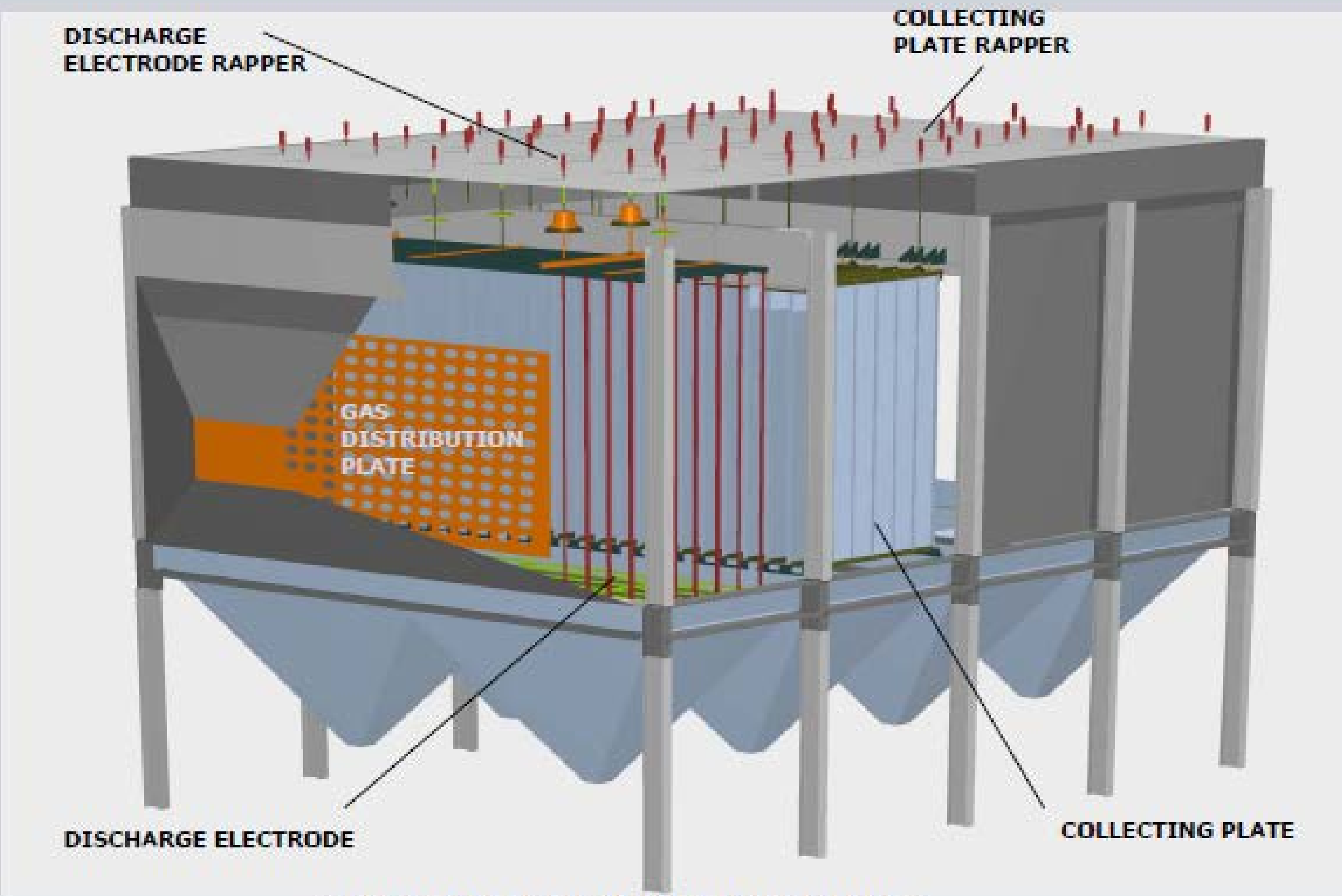
- **In = PM loading entering ESP, lb/MMBtu**
- **Out = PM loading exiting the ESP, lb/MMBtu**

Eq. C - Various mass & energy balance equations related to amount (heat input) from natural gas co-firing with coal, to predict the flow rate composition, and properties of the flue gas and particulate matter entering the ESP.



Variable Intensity Gravity Rapped (VIGR) Precipitator

SIEMENS



CUTAWAY SHOWING INTERNALS

 Energy Sector

Slide from Siemens

- **Concepts – Upgraded ESPs**
  - ***HFTR***
  - ***Sectionalization***
  - ***RD electrodes***
  - ***Upgraded rappers***
  - ***Additional fields***
  - ***Demolish existing ESP and retrofit new ESP in parallel***
  - ***Convert ESP to PJFF***
  - ***Other concepts***

Various Types of HFTR Systems

General layout The FF consists of a number of component groups

FLSMIDTH

Cleaning principle
(Needle Felt Bag & Glass Bag)

Control system

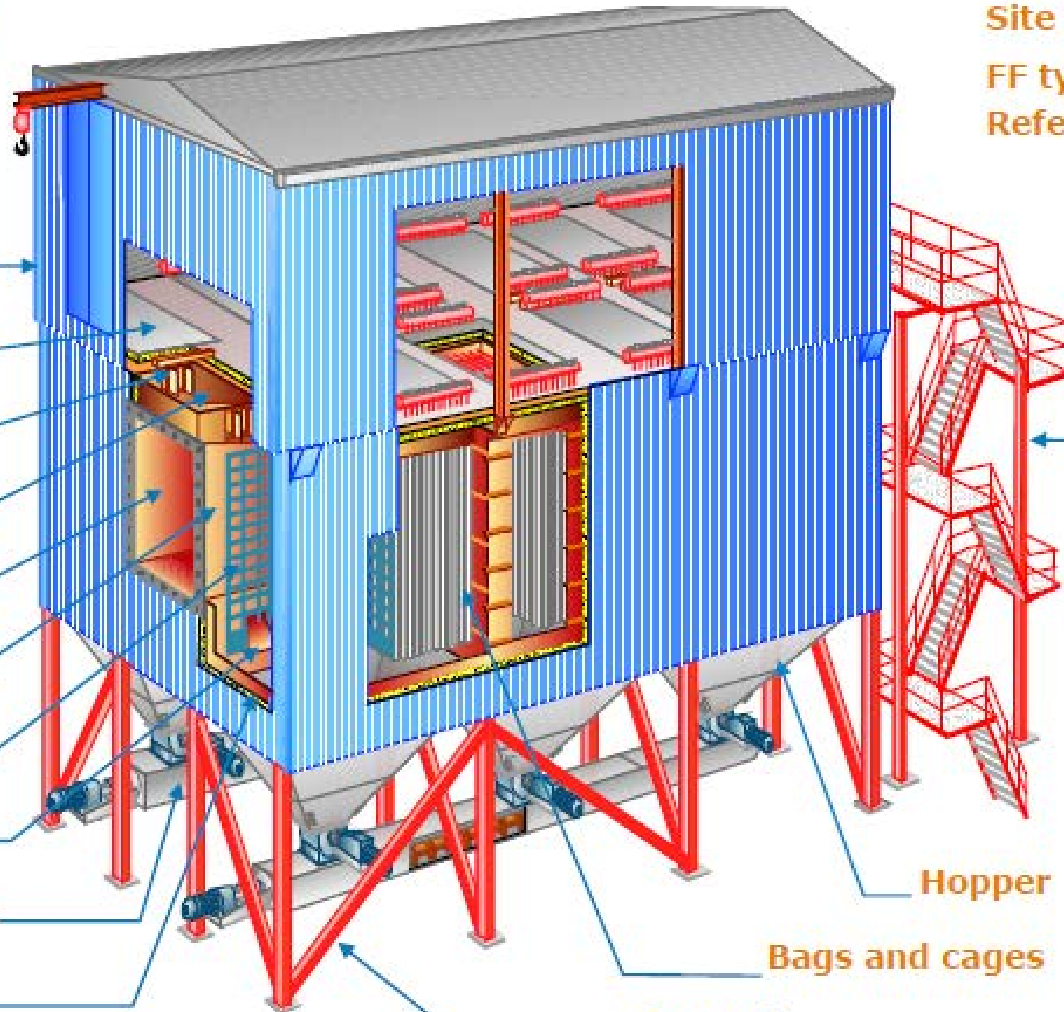
Construction

Highlights

Site photos

FF types

References



Return to front page

Slide from FLSmidth

Inform replacement bag/cage supplier of the new flue gas resulting from the coal to gas conversion project.

- New Bags
  - QA/QC fit demo

- New Cages

Impacts on Particulate Matter Control Technologies due to Natural Gas Conversion or Co-firing - examples

- **Electrostatic Precipitators (ESP**
  - inlet flue gas decreased fly ash inlet loading
  - possible changes in inlet flue gas temperature, flow rate, and distribution
  - inlet flue gas increased moisture content
  - possible changes in inlet flue gas PFA LOI
  - inlet flue gas decreased SO_3/H_2SO_4 content
  - changes in FGC feed rate
  - possible change in inlet fly ash size distribution
  - investigate possible ESP de-energization (100% natural gas firing)
  - other impacts

Impacts on Particulate Matter Control Technologies due to Natural Gas Conversion or Co-firing - examples

- **Fabric Filters (PJFF or RAFF)**
  - inlet flue gas decreased fly ash inlet loading
  - changes in inlet flue gas flow rate & distribution
  - inlet flue gas increased moisture content
  - investigate concept of de-bagging (100% natural gas firing)
  - other impacts
- **Wet Electrostatic Precipitator (WESP)**
  - investigate adjusting irrigation wash water to address water balance issues, if required)
  - other impacts

Sulfur Trioxide (SO_3/H_2SO_4) Control

Sulfur Trioxide (SO_3/H_2SO_4) Control

- Dry Sorbent Injection (HL DSI, Trona DSI, etc.)
- Wet Sorbent Injection (SBS)
- Wet Electrostatic Precipitator (WESP)
- Wet Flue Gas Desulfurization (WFGD)
- Dry Flue Gas Desulfurization (CDS, NID, SDA, etc.)
- Air Heater (APH)
- Coal Fuel Blending
- Coal Fuel Switch (PRB)
- Gas Reburn (FLGR, etc.)
- Supplemental firing with Natural Gas
- Gas Conversion
- Other SO_3/H_2SO_4 control technologies

Concept – DSI/WSI to reduce SO3/H2SO4, HCl emissions:

- ***Hydrated lime → $Ca(OH)_2$***
- ***Trona → $Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$***
- ***Sodium bicarbonate → $NaHCO_3$***
- ***Other Reagents***

UCC VIPER ™ Mill

Example Sorbent Storage Silos

SO3 Control Installation - Delta Wing for DSI

Babcock Power

Impacts on SO3/H2SO4 Control Technologies due to Natural Gas Conversion or Co-firing (examples)

- **Dry or wet sorbent injection (DSI/WSI) for sulfur trioxide/sulfuric acid (SO_3/H_2SO_4) reduction**
  - inlet flue gas decreased SO3/H2SO4 content
  - decreased sorbent feed rate
  - changes in flue gas distribution
  - changes in DSI/WSI turn-down ratio
  - investigate turning off DSI/WSI (e.g. if 100% natural gas firing)
  - other impacts

Mercury (Hg) Control

Mercury (Hg) Control

- Calcium Bromide on Coal ($CaBr_2$, or other Hg oxidation additives , $CaCl_2$, NH_4Cl, etc.)
- SCR (oxidation of Hg, SCR catalyst regeneration, new catalyst, etc.)
- Dry Sorbent Injection (HL DSI, Trona DSI, etc.)
- Wet Sorbent Injection (SBS)
- Air Heater (APH)
- Activated Carbon Injection (ACI)
- Amended Silicate Sorbent Injection (AS)
- Wet Flue Gas Desulfurization (WFGD, MRE, PAC, etc.)
- Gore™ (GMCS)
- Dry Flue Gas Desulfurization (CDS, NID, SDA, etc.)
- Coal Un-burned Carbon (ash LOI)
- Coal Fuel Blending
- Coal Fuel Switch (PRB)
- Gas Reburn (FLGR, etc.)
- Supplemental firing with Natural Gas
- Gas Conversion
- Other Hg control technologies

Activated Carbon Injection (ACI) – Hg Reduction - examples

Impacts on Mercury Control Technologies due to Natural Gas Conversion or Co-firing - examples

- **Calcium bromide ($CaBr_2$) on coal to oxidize mercury**
  - decreased $CaBr_2$ feed rate
  - possible change in furnace flue gas mercury speciation
  - investigate turning off additive injection (e.g. if 100% natural gas firing)
  - other impacts

- **Activated Carbon (ACI) or Amended Silicate (AS) Injection**
  - decreased PAC/AS injection rate
  - changes in inlet flue gas distribution
  - possible changes in PFA LOI
  - investigate turning off PAC/AS injection (e.g. if 100% natural gas firing)
  - other issues

- **Mercury re-emission inhibitor (MRE) in WFGD**
  - inlet flue gas decreased mercury content
  - inlet flue gas increased moisture content (impacting AST)
  - maintain proper MRE concentration and feed rate, ORP, pH
  - investigate turning off MRE injection (e.g. under high natural gas burn rates)
  - other impacts

- If coal unit is converted to natural gas firing (or supplemental firing or co-firing), the resulting inlet flue gas will contain less mercury content, which may assist in meeting MATS requirements.

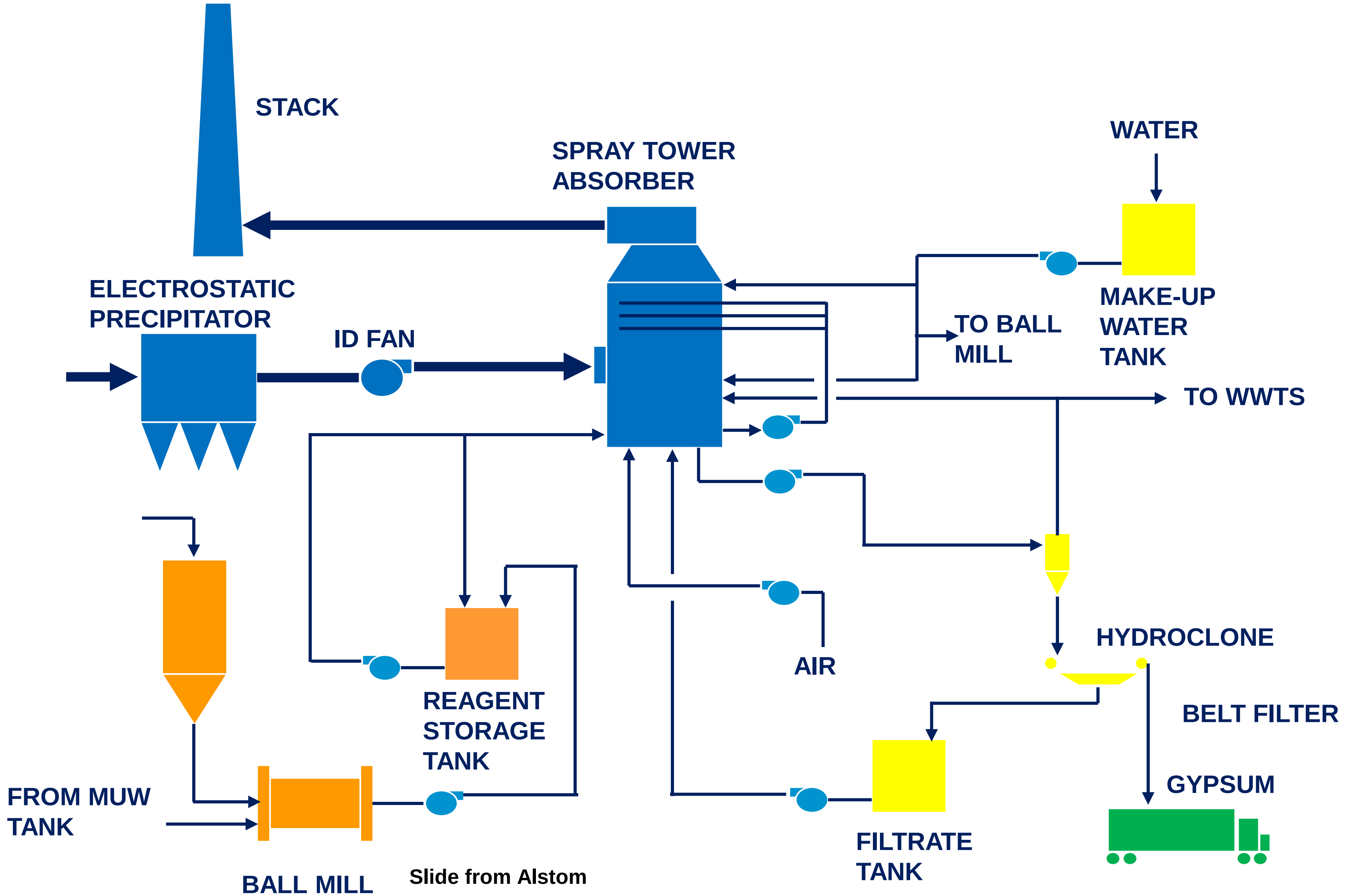
Sulfur Dioxide (SO_2) and Hydrochloric Acid (HCl) Control

Sulfur Dioxide (SO_2) and Hydrochloric Acid (HCl) Control

- Wet Flue Gas Desulfurization (WFGD, with WWTS or Closed loop, etc.)
- Dry Flue Gas Desulfurization (CDS, NID, SDA, etc.)
- Dry Sorbent Injection (HL DSI, Trona DSI, etc.)
- Multi-pollutant control (ReACT for SO_2 control, etc.)
- Coal Fuel Blending
- Coal Fuel Switch (PRB)
- Gas Reburn (FLGR, etc.)
- Supplemental firing with Natural Gas
- Gas Conversion
- Other SO_2 control technologies

Wet Flue Gas Desulfurization (WFGD) Technologies

Wet Flue Gas Desulfurization (FGD) System - example

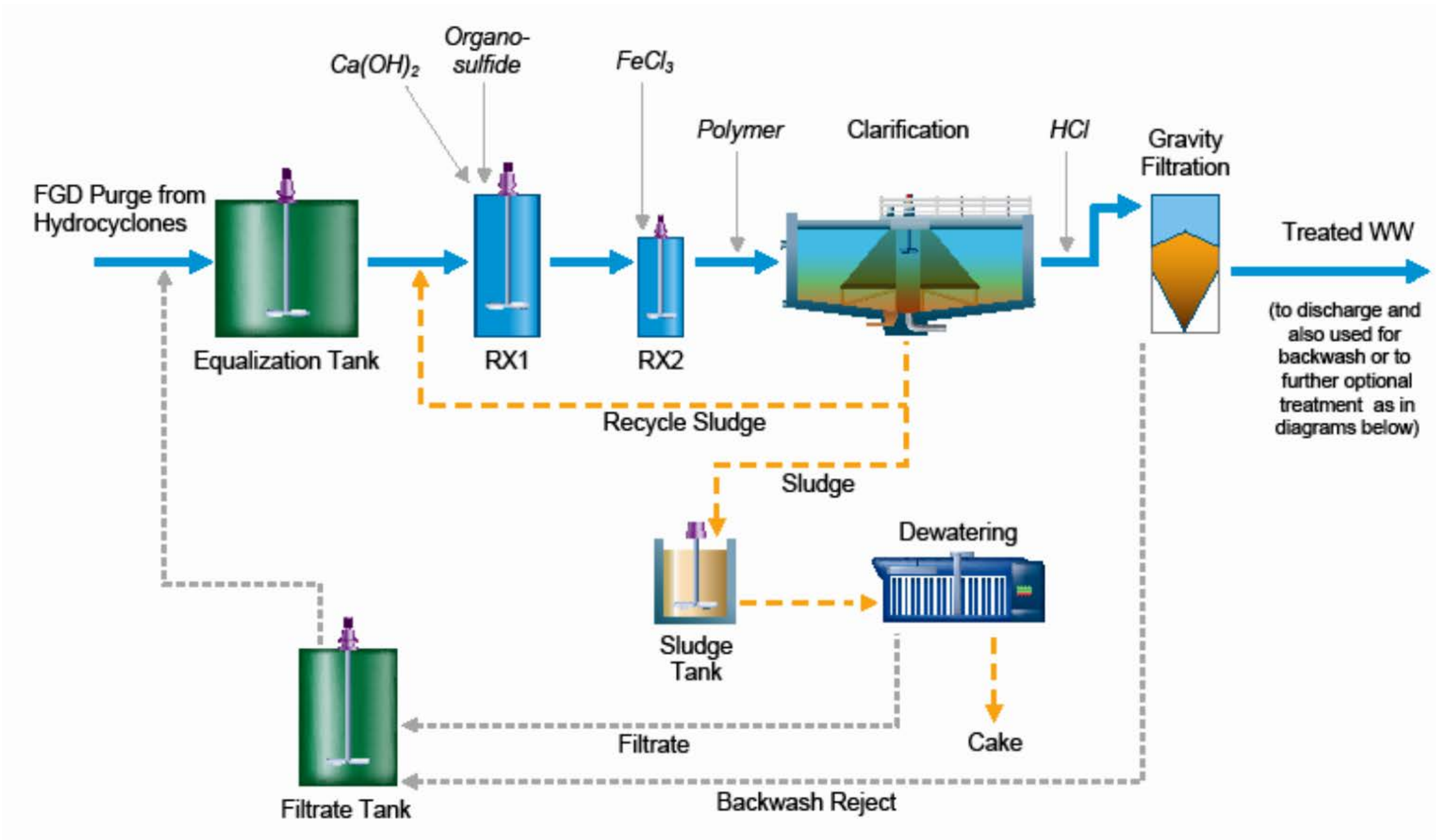


Slide from Alstom

- **Wet flue gas desulfurization (LSFO, Lime, etc.)**
  - inlet flue gas decreased SO_2 loading
  - inlet flue gas increased moisture content (impacting AST, investigate existing materials of construction)
  - possible change in inlet flue gas temperature
  - possible change in inlet flue gas distribution
  - need to maintain proper pH, TSS, TDS, alkalinity, ORP
  - investigate adjusting mist eliminator wash cycle duration or timing to address WFGD water balance potential issues
  - possible changes in byproduct gypsum or sludge dewatering sequence or timing (e.g. % by weight solids in feed slurry, decreased solids production, possible impact on gypsum size distribution, etc.)
  - investigate influence of inlet flue gas VOC, NH_3 slip, NOx content (along with lower SO_2/HCl/etc.) on WFGD chemistry & pH during of high NG gas heat input.
  - investigate energy consumption management issues including absorber recycle pumps and/or oxidation air blowers in service
  - investigate WFGD bypass (under 100% natural gas firing)
  - other impacts

WFGD Waste Water Treatment (WWTS) Technologies

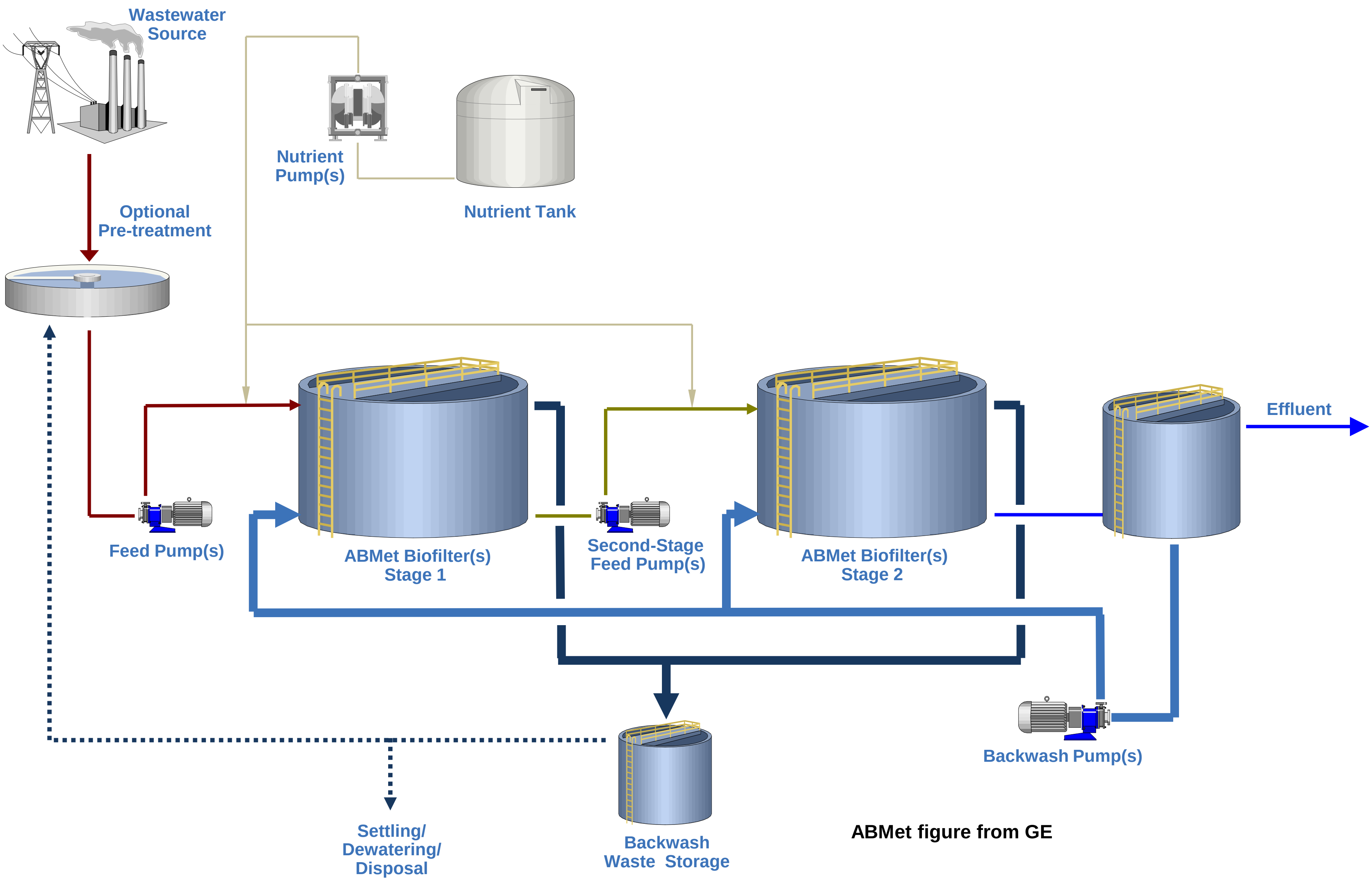
WFGD Waste Water Treatment
Physical / Chemical System – example



WWTS figure from Siemens

ABMet Flow Diagram – Bio WWTS Technology

(Anoxic Bio Stage 1 for Nitrate & Selenium removal and Anoxic Bio Stage 2 for Selenium polishing removal – example)



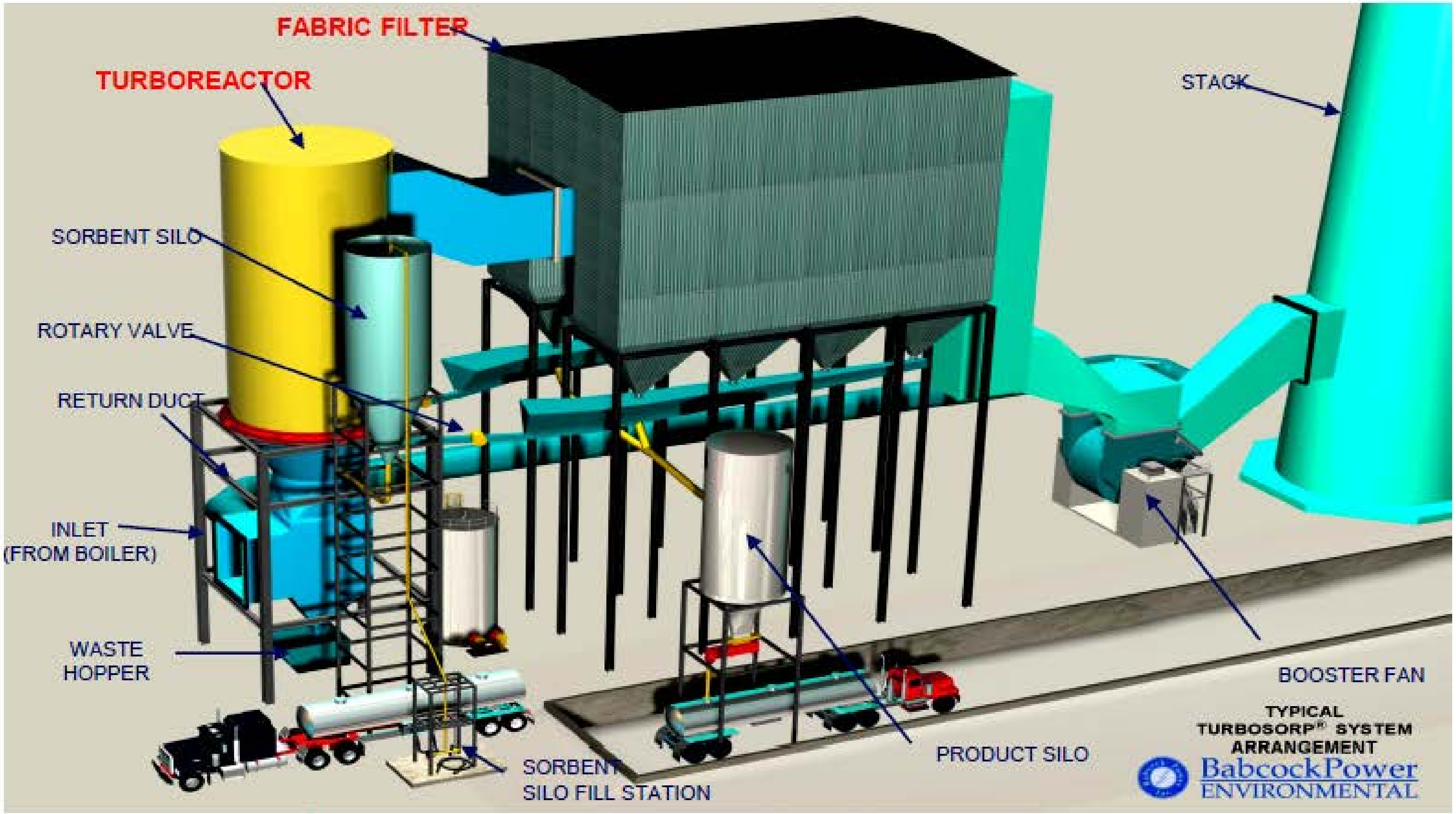
ABMet figure from GE

Impacts on WFGD Waste Water Treatment (WWTS) due to Natural Gas Conversion or Co-firing - examples

- **WFGD waste water treatment systems (WFGD WWTS)**
  - changes in influent waste water composition and temperature
  - investigate if heat exchanger is required
  - possible decreased WWTS sludge production
  - possible change in WWTS reagent usage rates
  - investigate influence of inlet flue gas VOC, NH_3 slip, NOx, etc. content on WFGD chemistry and WWTS influent during cases of high natural gas heat input
  - possible more frequent checks of equalization tank composition to WWTS feed stream
  - need to continue to maintain effluent quality
  - investigate impacts to WWTS if WFGD system were bypassed
  - other impacts

Dry Flue Gas Desulfurization (DFGD) Technologies

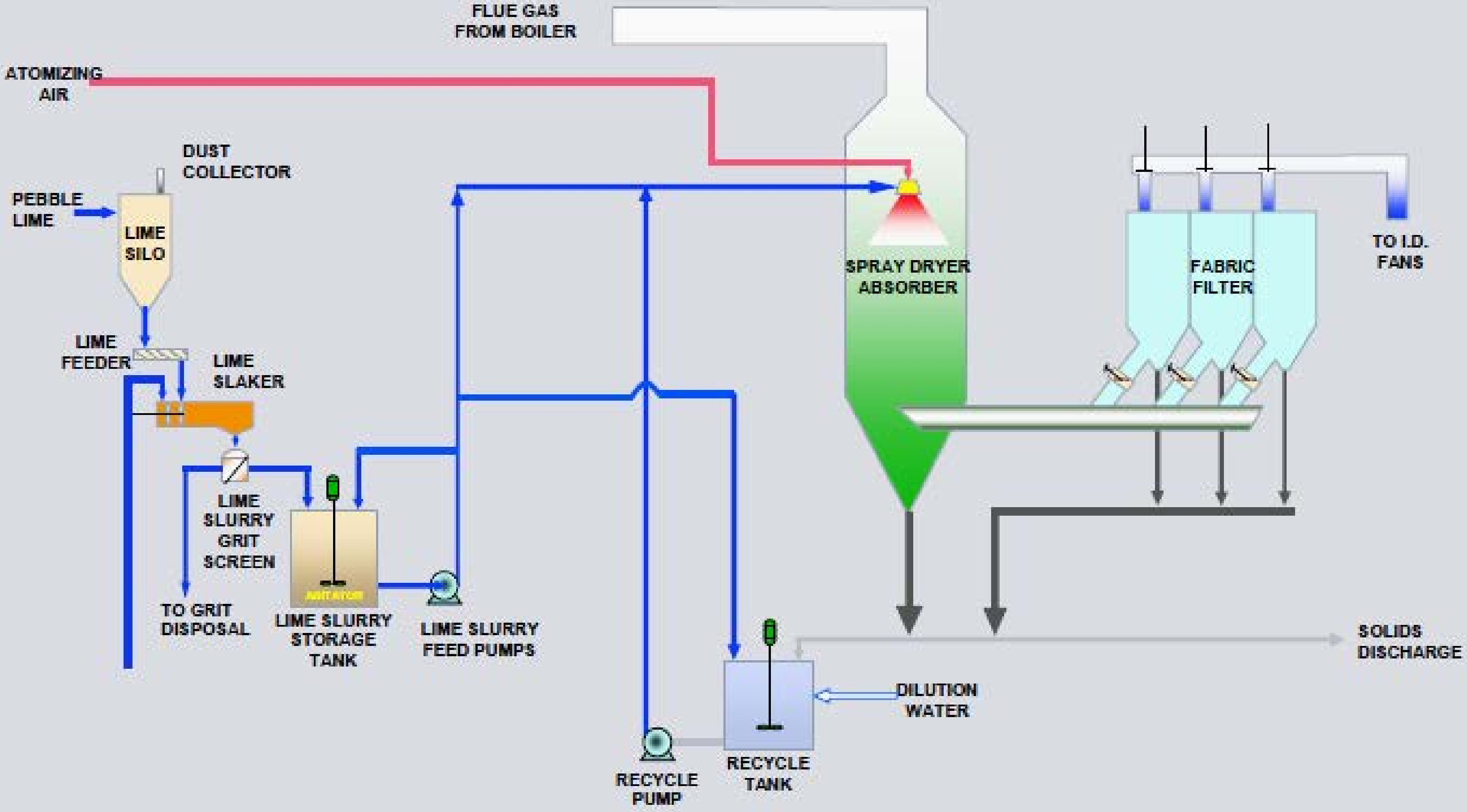
Turbosorp® Single Unit GA



Slide from BPE

Spray Dryer Absorber Technology

SIEMENS



Slide from Siemens

- **Dry flue gas desulfurization (SDA, CDS, NID, etc.)**
  - inlet flue gas decreased SO_2 loading
  - decreased lime usage rate
  - decreased dry scrubber solid byproduct production
  - inlet flue gas increased moisture content (impacting AST)
  - possible change in SDA/CDS/NID flue gas operating temperature (due to AST) to avoid solids deposition
  - possible change in inlet flue gas temperature
  - possible change in inlet flue gas distribution
  - need to continue feeding lime reagent for SDA/CDS/NID while co-firing coal (keep lime flowing if water spray is on to avoid corrosion)
  - investigate if SDA atomizers can be pulled from service (e.g. under 100% natural gas firing operation)
  - investigate impact of inlet flue gas CO_2 , moisture, NOx, etc content on chemistry within DFGD and byproduct, for natural gas high heat input conditions (e.g. $CO_2 + Ca(OH)_2 \rightarrow$ CaCO3 + H_2O).
  - other impacts

Carbon Monoxide and Volatile Organic Compound Control

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC) Control

- Combustion Optimization (including computer pattern recognition, network, PI, LNB with combustion & operation balancing NOx/CO/VOC issues, etc.)

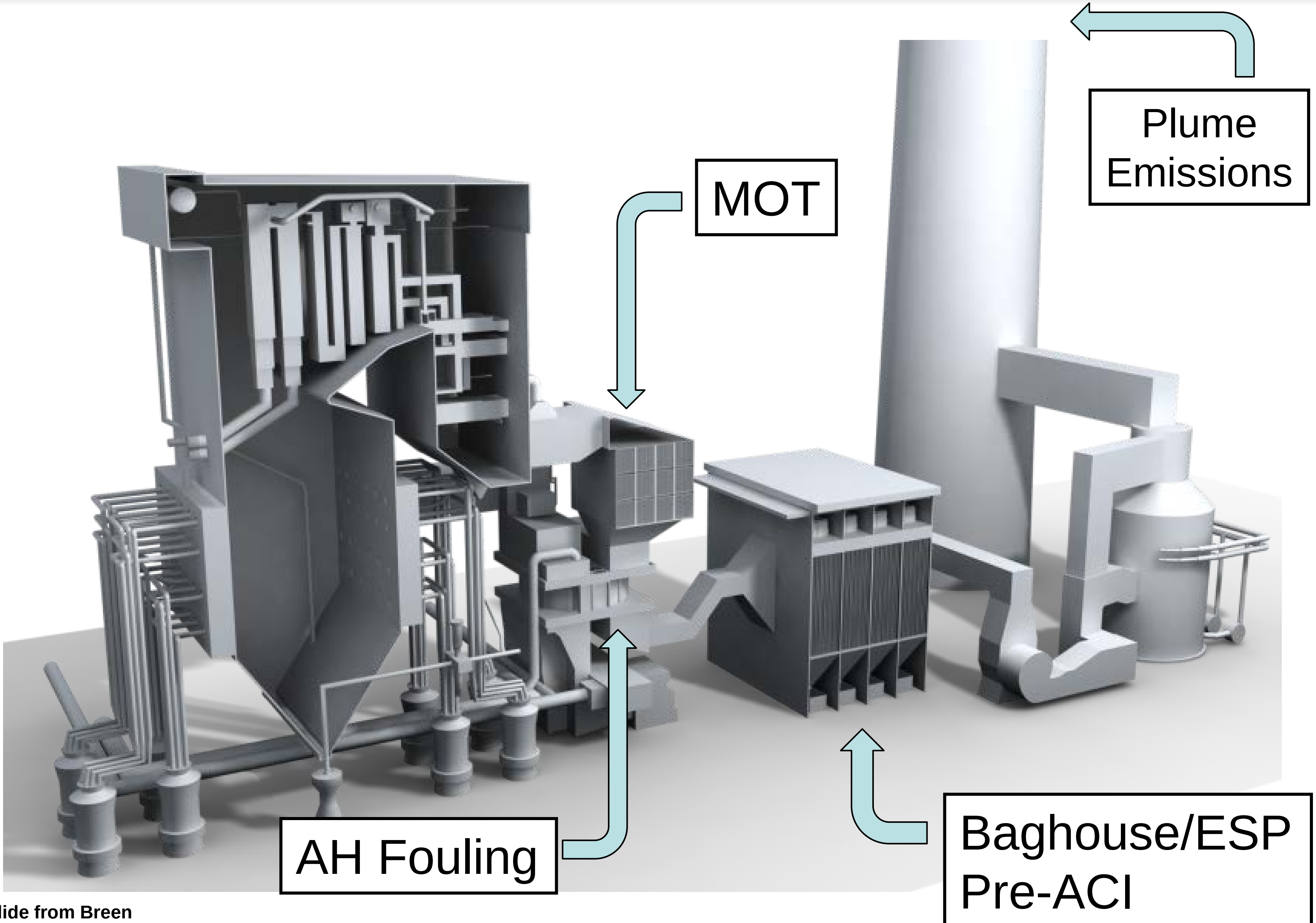
- Other CO/VOC control technologies

Existing Plant Equipment Related to AQCS

Existing Plant Systems Related to AQCS - examples

- Fuel Handling
- Burners
- Economizer
- APH
- Breen Probes and Other Instrumentation
- AQCS byproducts handling and storage
- Fans
- Stack
- CEMS
- BOP
- Other areas

Sulfur Condensable Impact Points



Slide from Breen

- **Air pre-heaters (APH, regenerative or tubular)**
  - inlet flue gas decreased coal ash content
  - inlet flue gas increased moisture content
  - possible changes in inlet flue gas temperature
  - potential changes in inlet flue gas, for example, investigate potential changes in NH_4HSO_4 /HBr/SO_3/H_2SO_4 deposition & sublimation, etc.
  - investigate APH modifcations (100% natural gas firing)
  - other impacts

- **Expansion Joints and Ductwork**
  - inlet flue gas decreased fly ash inlet loading
  - possible changes in inlet flue gas distribution
  - increased flue gas moisture content
  - may need to thoroughly clean furnace, APH, expansion joints and ductwork, stack (for permanent 100% natural gas firing conditions), if ESP power levels are decreased or de-energized, etc.
  - other impacts

- **Dry ash handling systems or saleable PFA processing systems**
  - decreased flyash production rate
  - investigate possible change in PFA LOI
  - investigate turning off BA and/or PFA systems (if permanent 100% natural gas firing conditions)
  - other impacts

- **Stack and CEMS**
  - changes in stack flue gas specie conc. values (SO_2, NOx, Hg, CO/VOC, etc.)
  - changes in stack bulk flue gas conc. values (opacity, $CO_2/O_2/H_2O$, etc.)
  - investigate changes in stack flue gas physical properties (temperature, flow rate, etc.)
  - stack inspection (e.g. with regard to potential impacts due to permanent natural gas firing)

BOP AQCS Equipment Potentially Impacted due to Natural Gas Conversion - examples

- As indicated, while co-firing or supplemental firing natural gas, while maintaining continuous lower-load through gas igniters or burners, investigate low-load flue gas temp & higher moisture content issues, investigate potential lower-load corrosion issues, need to continue feeding reagent for FGDS while co-firing, etc.

- Natural Gas Leak Detection

- Other AQCS & BOP related equipment impacts

Summary

Summary

- Strategy choices include coal to natural gas conversion (or supplemental firing or co-firing) to stay within compliance.
- Coal to gas conversion will result in changes to the flue gas composition/properties.
- Coal to gas conversion can impact existing air quality control systems (AQCS) of coal fired power plants.
- In general, existing coal-fired AQCS technologies are compatible with the flue gas from gas conversion, with some possible design modifications, by-pass (if required), and/or operation and maintenance (O&M) changes as needed.

Chris Wedig, CB&I
AQCS Equipment Specialist
E: christopher.wedig@cbi.com
P: 617-589-5737

Joe Jankauskas, CB&I
Project Manager
E: joe.jankauskas@cbi.com
P: 856-482-3077

Greg Fynan, CB&I
Senior Engineering Specialist
E: gregory.fynan@cbi.com
P: 617-589-4081

CB&I

Extra Slides

The following are extra slides, providing additional background information for the reader.

Additional Slides

Fuel Description

Natural Gas

Shale Gas (raw) – Principal Composition
Raw Gas Before Processing - examples

Well	C1	C2	C3	CO2	N2
A	80.3	8.1	2.3	1.4	7.9
B	81.2	11.8	5.2	0.3	1.5
C	91.8	4.4	0.4	2.3	1.1
D	93.7	2.6	0.0	2.7	1.0
E	79.4	16.1	4.0	0.1	0.4
F	82.1	14.0	3.5	0.1	0.3
G	83.8	12.0	3.0	0.9	0.3
H	95.5	3.0	1.0	0.3	0.2
I	97.3	1.0	0	1.0	0.7
J	87.7	1.7	2.5	8.1	NR
K	88.0	0.8	0.8	10.4	NR
L	91.0	1.0	0.6	7.4	NR
M	92.8	1.0	0.6	5.6	NR
N	27.5	3.5	1.0	3.0	65.0
O	57.3	4.9	1.9	0	35.9
P	77.5	4.0	0.9	3.3	14.3
Q	85.6	4.3	0.4	9.0	0.7

Reference "Composition Variety Complicates Processing Plans for US Shale Gas"

Natural Gas Fuel – Typical Components Analyzed

- **Methane** (major component)
- **Ethane**
- Propane
- iso - Butane
- normal - Butane
- iso - Pentane
- normal - Pentane
- Hexanes plus
- Hydrogen
- Ethylene
- Nitrogen
- Carbon Dioxide
- Oxygen
- Carbon Monoxide
- Hydrogen Sulfide
- Mercaptans
- Moisture
- Trace Components

Trace Hydrocarbons in Natural Gas – analyzed - examples

- Aliphatics (cyclopentane, hexanes, heptanes, octanes, etc.)
- Aromatics (benzene, toluene, etc.)
- Sulfur Components (H_2S, sulfides, mercaptans, etc.)
- Halocarbons
- Nitrogen Compounds (ammonia, etc.)
- Oxygenates (methanol, etc.)
- Other Elements & Compounds (As, Hg, NO, NOx, Rn, etc.)

Based on reference – Gas Research Institute (GRI-94/0243.2)

Other Elements and Compounds Natural Gas – examples

Other Element or Compound	# of Samples	Range	Median
Total Arsenic, micro-gm/m3	10	<5	<5
Total Mercury, micro-gm/m3	19	<0.02 to 0.2	<0.2
NOx, ppmv	19	<0.05 to 130	<0.05
Radon	18	<1 to 110	3

Based on reference – Gas Research Institute (GRI-94/0243.2)

Gas Processing - examples

Gas processing removes one or more components from harvested gas to prepare it for use.

Common components removed to meet pipeline, safety, environmental, and quality specifications include hydrogen sulfides (H2S), carbon dioxide (CO2), nitrogen (N2), heavy hydrocarbons, and water (H2O).

The technique employed to process the gas varies with the components to be removed as well as with the properties of the gas stream (e.g. temperature, pressure, composition, flow rate).

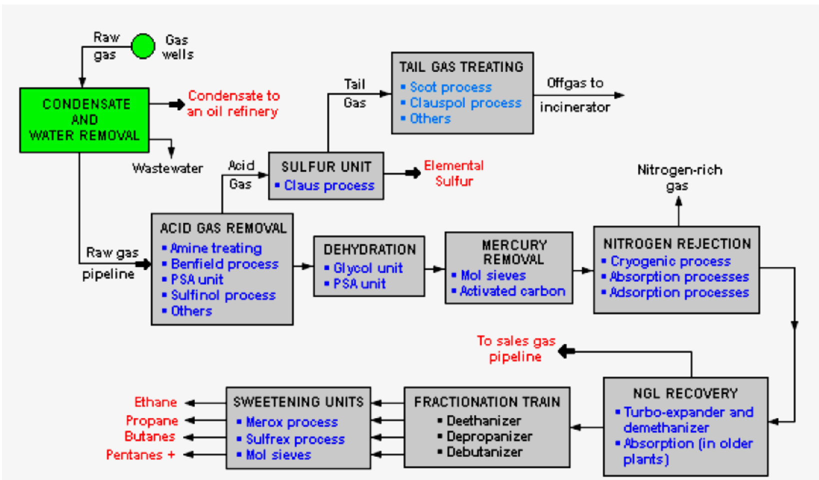
Background Information (which can be read later)

There are many different types of processing technologies, these are some examples, there are other processes. Acid-gas removal is commonly by absorption of the H2S and CO2 into aqueous amine solutions. This technique works well for high-pressure gas streams and those with moderate to high concentrations of the acid-gas component. Physical solvents such as methanol or the polymer DEGP, or Selexol may also be used in some cases. And, if the CO2 level is very high, such as in gas from CO2 flooded reservoirs, membrane technology affords bulk CO2 removal in advance of processing with another method. For minimal amounts of H2S in a gas stream, scavengers can be a cost effective approach to H2S removal. Natural gas that becomes saturated with water in the reservoir requires dehydration to increase the heating value of the gas and to prevent pipeline corrosion and the formation of solid hydrates. In most cases, dehydration with a glycol is employed. The water rich glycol can be regenerated by reducing the pressure and applying heat. Another possible dehydration method is use of molecular sieves that contact the gas with a solid adsorbent to remove the water. Molecular sieves can remove the water down to the extremely low levels required for cryogenic separation processes. Distillation uses the different boiling points of heavier hydrocarbons and nitrogen for separation. Cryogenic temperatures, required for separation of nitrogen and methane, are achieved by refrigeration and expansion of the gas through an expander. Removal of the heavy hydrocarbons is dictated by pipeline quality requirements, while deep removal is based on the economics of NGL production.

Reference “Composition Variety Complicates Processing Plans for US Shale Gas”

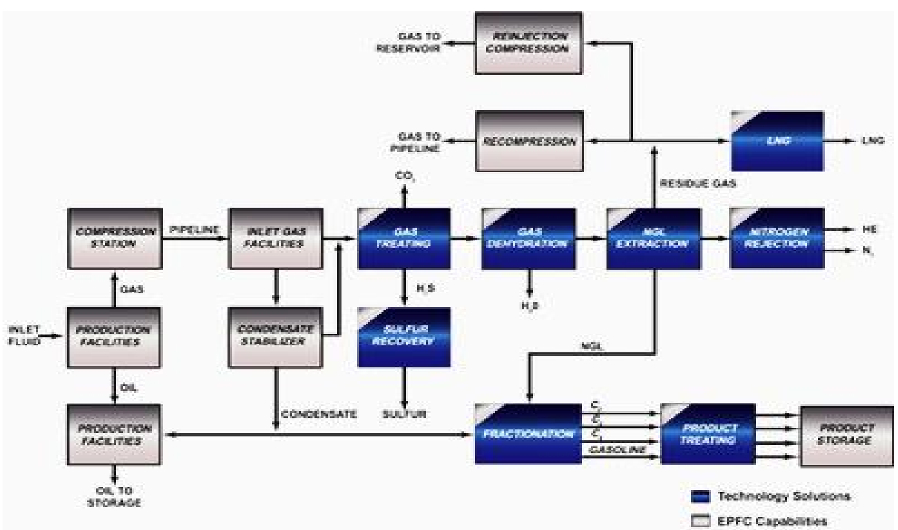
Concepts Related to Processing Raw Natural Gas to Produce Pipeline Quality Natural Gas and Other Products of the Natural Gas Value Chain - examples

Typically, raw natural gas (e.g. raw gas well) is processed to remove impurities. The exact processing scheme can vary depending on properties of the raw gas stream, the end-user, and other site specifics. Below presents examples of some of the different types of fundamental concepts (not listed in order of processing) that may be employed (there are other concepts).



- **Raw gas wells**
- **Condensate and water removal**
- **Acid gas removal**
- **Dehydration**
- **Mercury removal**
- **Nitrogen rejection**
- **NGL recovery**
- **Fractionation train**
- **Sweeting units**

Source: Natural Gas Processing



- **Field development**
- **Pre-treatment**
- **Gas conditioning and treating**
- **Sulfur removal**
- **Fractionation**
- **Nitrogen rejection**
- **Helium recovery**
- **Deep ethane extraction**
- **NGL recovery**
- **Dehydration**
- **LPG recovery**
- **LNG**
- **Liquid product treating**
- **Upgrading of low value gas**
- **Conceptual design through commissioning and operator training across the entire natural gas value chain**
- **Other concepts**

Source: CB&I Website

As indicated, there are other concepts, for example see Oil & Gas Journal article "New NGL Recovery Process Provides Viable Alternative" and other publications.

Additional Slides

Flue Gas Description

Natural Gas

Carbon Dioxide (CO_2) from Coal and Gas Fuels - examples

Fossil Fuel Type (examples)	Total Carbon Content (% ultimate carbon by weight)	Higher Heating Value (HHV, as received basis) (Btu/pound fuel)	CO_2 Production Rate (lb CO_2 per million Btu, HHV)
Coal – A	83.7	11,890	258
Coal – B	74.0	12,540	216
Coal – SB	70.3	9,190	280
Coal – L	63.3	7,090	327
Natural Gas –1	75.25	23,170	119
Natural Gas –5	64.84	20,160	118

Additional Slide

Coal to Gas Conversion

AQCS Project Description

AQCS Related Activities of a Coal to Gas Conversion Project

- Services
- Inspection of Existing AQCS
- Determination of Impact of Conversion Project to Existing AQCS (studies)
- Engineering & Design
- Procurement
- Fabrication
- Shipment and Delivery
- Installation
- Training
- Commissioning
- Start-up
- Testing
- Operation & Maintenance
- Other project related activities

Examples of Scenarios A1, A2, and B

As the focus of this presentation, the rest of the slides relate to the potential impacts of coal to natural gas conversion or co-firing on existing AQCS of a coal-fired power plant, for Scenarios A1, A2, and B, where natural gas is burned in a coal-fired furnace and the AQCS is employed, modified, or by-passed, as required.

Scenario A1 - Full (100%) conversion to natural gas project (retain ability to burn coal for the future, if natural gas pricing increases), burn natural gas fuel in existing boiler with required modifications, by-pass AQCS that is not needed, de-energize AQCS not needed, keep any needed AQCS & Stack functional with modifications (if required), BOP, etc.

Scenario A2 - Full (100%) conversion to natural gas project (permanently, no coal firing in the immediate future), burn natural gas fuel in existing boiler with required modifications, permanent by-pass of AQCS that is not needed, permanently de-energize AQCS not needed, keep any needed AQCS & Stack functional with modifications (if required), BOP, etc.

Scenario B - Coal firing with supplemental or co-firing of natural gas (with continued routine coal-firing) in existing boiler with required modifications, keep needed AQCS & Stack functional with modifications (as required), BOP, etc.

Example 1 – Scenario A1 (re-fuel)

- full (100%) conversion to natural gas project (retain ability to burn coal for the future, if natural gas pricing increase compared to coal pricing)
- burn natural gas fuel in existing boiler, with required modifications
- by-pass AQCS that is not needed
- de-energize AQCS not needed
- keep any needed AQCS & stack functional with modifications (if required)
- BOP modifications, where required
- new natural gas pipeline proposed to generating station

Example 2 – Scenario A2 (re-fuel)

- full (100%) conversion to natural gas project (*permanently*, no coal firing in the future)
- burn natural gas fuel in existing boiler, with required modifications
- permanently by-pass of AQCS that is not needed,
- *permanently* de-energize AQCS that are not needed
- keep any needed AQCS & stack functional with modifications
- BOP modifications, where required
- new natural gas pipeline proposed to generating station

Example 3 – Scenario B (re-fuel)

- coal firing with supplemental or co-firing of natural gas (with continued routine coal-firing)
- burn natural gas fuel in existing boiler, with required modifications
- keep needed AQCS & stack functional with modifications (as required)
- BOP modifications, where required
- existing natural gas pipeline already employed at the generating station

Examples of Scenario C – Repowering

To address the subject, the following slide presents examples of proposed projects burning 100% natural gas, repower existing facility with natural gas-fired combustion turbine, natural gas in-duct firing (if required) and HRSG, retire existing coal-fired boiler and existing AQCS, modify BOP as required.

Example 1 – Scenario C (repowering)

- Redevelopment
- Retire existing coal units including the existing AQCS; all units have once through condenser cooling.
- Redevelopment on existing site with two 1 on 1 combined cycle gas turbine generator units, each with an air cooled condenser, Dry Low NOx Combustors, Selective Catalytic Reduction, and CO Oxidation Catalyst, one new two flue stack.

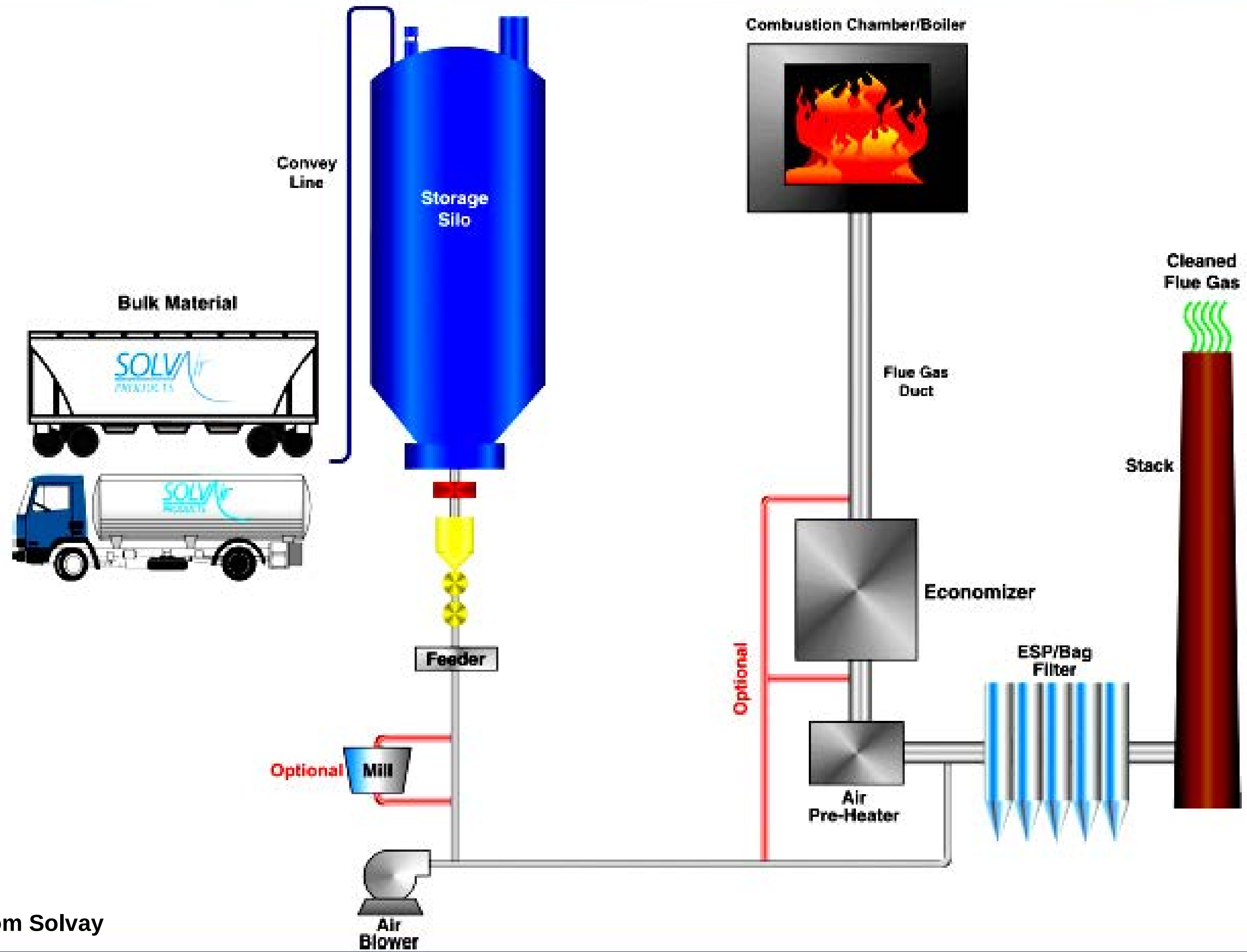
Example 2 – Scenario C (repowering)

- Redevelopment
- Retire existing coal unit including existing AQCS; unit has once through condenser cooling.
- Convert unit to a natural gas-fired combined cycle unit utilizing a high efficiency CTG exhausting to an HRSG generating steam for existing steam turbine
- Maximized use of existing infrastructure, systems, and transmission interconnection.
- Continued use of once thru cooling system (in light of upcoming 316 rules)
- Match new CTG and HRSG with existing STG and predicting start scenario
- Site remediation, limited area on site to accommodate construction lay down & craft parking
- New natural gas pipeline proposed to service community and the generating station

Additional Slides

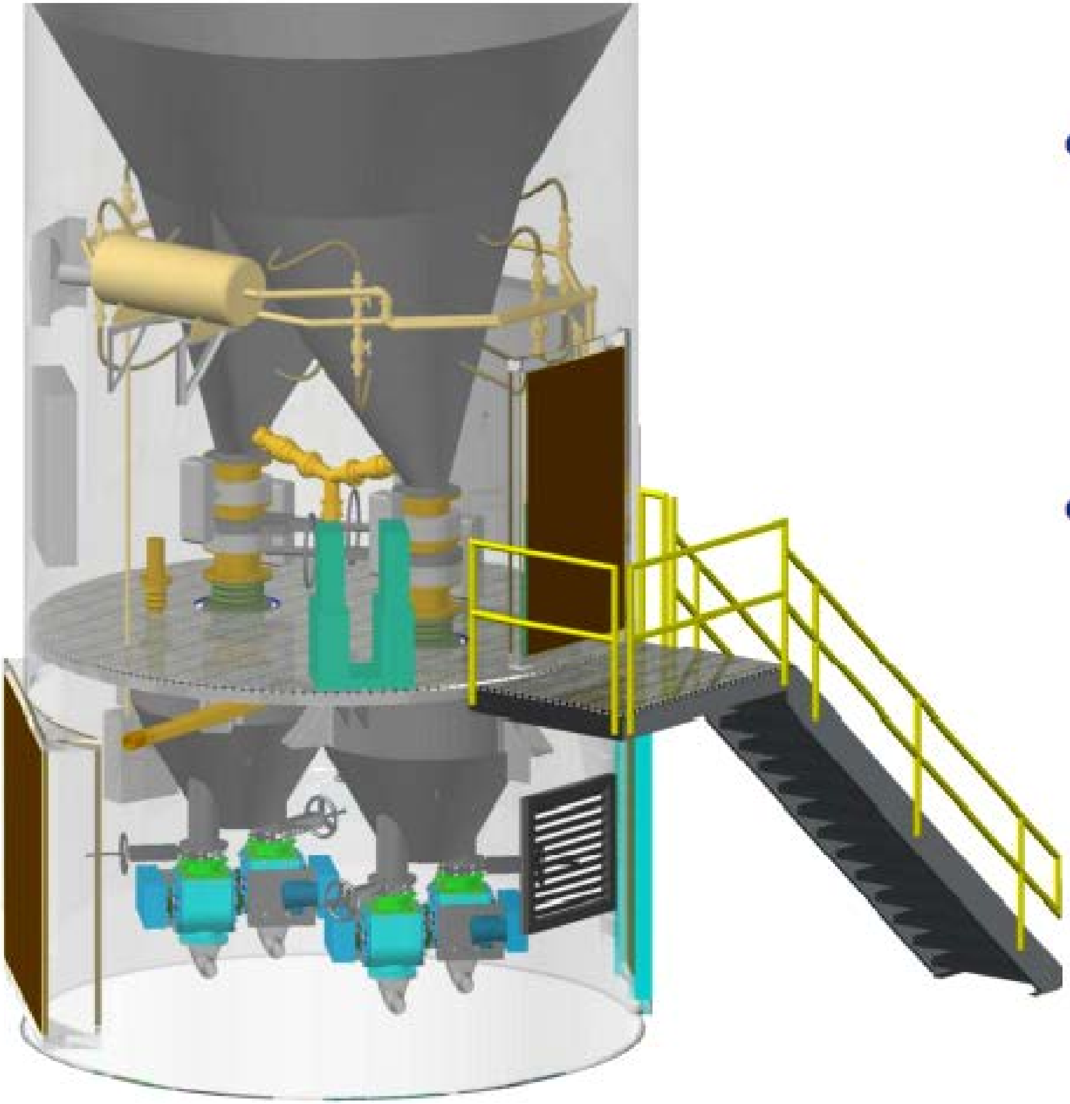
AQCS Technology Description

Example of a Utility DSI System



Slide from Solvay

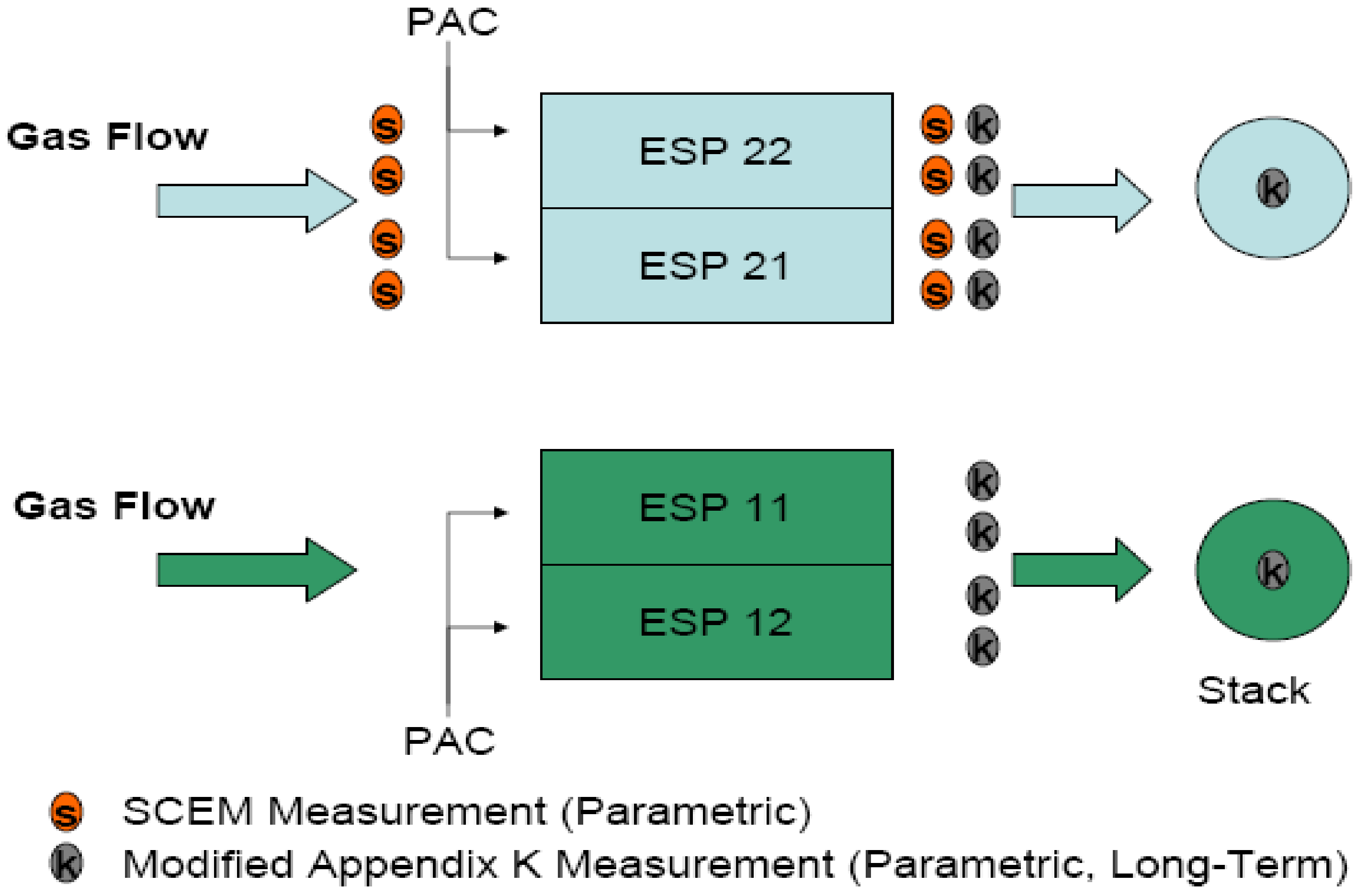
DSI System: Pre-Installed Arrangement



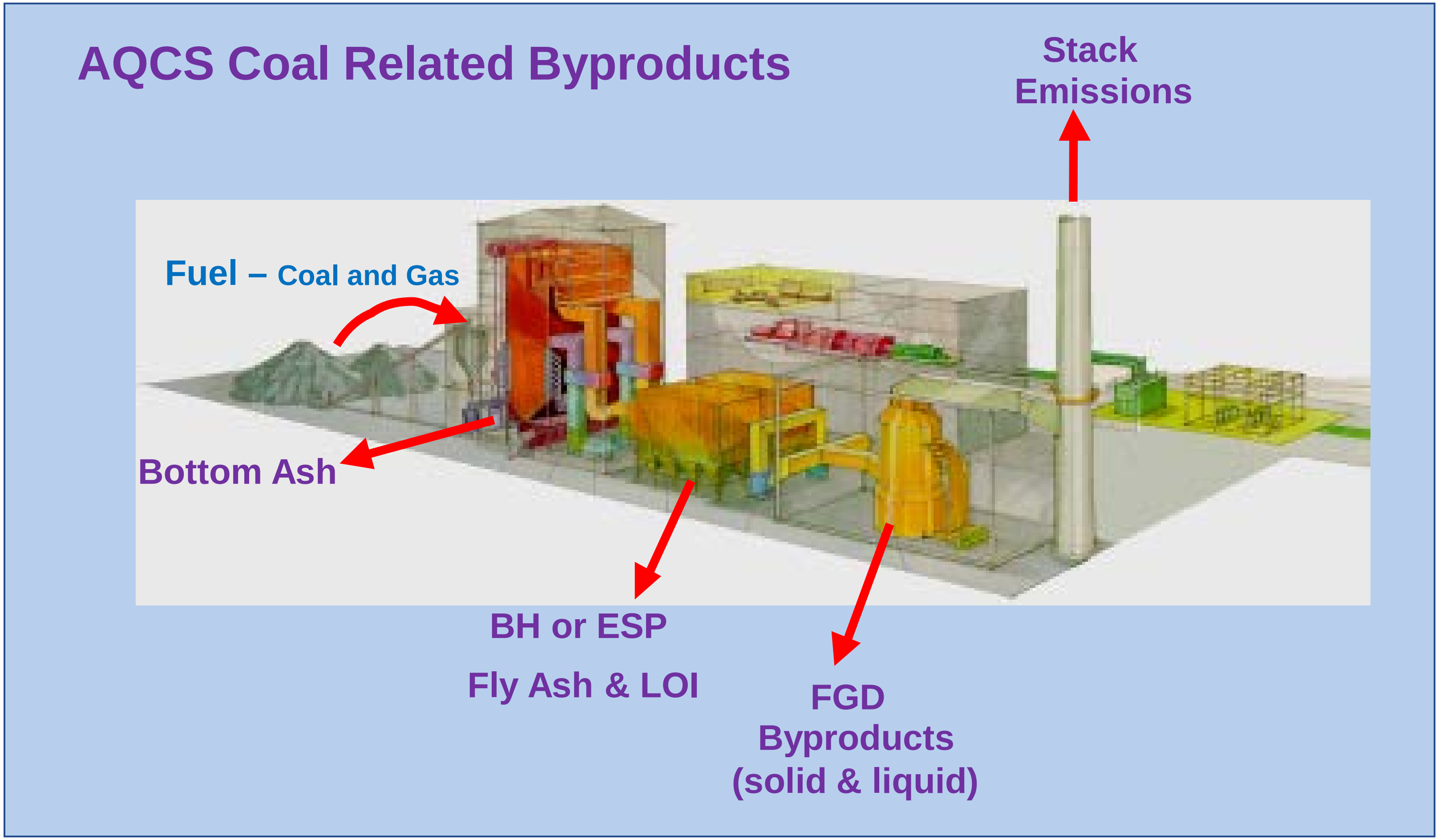
- **Second Equipment Level:**
  - Increased maintenance access
  - Location of electrical panels
  - Stairway and external platform provided
- **Weigh Hoppers:**
  - Suspended from second floor steel to provide increased maintenance access
  - Multiple feeders to provide redundancy
  - Sized to reduce cycles on refill valves

(Slide from CB)

Sorbent Injection with ESP –
Units 1 and 2 General Arrangement



AQCS Coal Related Byproducts
Coal to Gas Conversion (or co-firing) – examples



WFGD Waste Water Treatment Purpose - Generic

- A purpose of wet flue gas desulfurization (WFGD) waste water treatment system (WWTS) is to remove from the WFGD system chloride purge "blowdown" stream (CPS) the following:
  - Total suspended solids (TSS)
  - Trace metals (e.g., Hg, Se, As, etc.)
  - Adjust pH (if required)
  - Nitrogen-based species (NO_3^-, NO_2^-, NH_4^+, etc., if required)
  - Chemical oxygen demand (COD, as required)
  - Biological oxygen demand (BOD, as required)
  - Total dissolved solid species (TDS, if required)
  - Other constituents or parameters of the CPS (as required)

Types of Waste Water Treatment System (WWTS) - examples

- Waste Water Treatment System (WWTS) based on physical/chemical processes
- WWTS based on physical/chemical plus biological treatment processes
- WWTS based on physical/chemical plus engineered wetlands
- Zero liquid discharge (ZLD) concept based on closed loop WFGD (gypsum dewatering, and/or sludge stabilization)
- ZLD-based evaporation of WFGD chloride purge stream (CPS) in spray dryer absorber (SDA)
- ZLD based on evaporation/crystallization of WFGD CPS
- Other types of AQCS (CDS/NID/SDA/DSI & PJFF or ESP, ReACT, etc., with no CPS)

The wet FGD waste water treatment (WWTS) system could consists of:

- Physical/chemical processes for suspended solids, metals, pH, etc.
- Biological unit processes for nitrates, soluble selenium, and other species.

An equalization tank is installed upstream of the FGD WWTS to handle operating fluctuations in FGD system blowdown flow, chemistry, and suspended solids concentration. The equalization tank also accommodates more frequent boiler ramp-up, ramp-down, and shut-downs due to revised electrical grid dispatch of the coal-fired unit.

CB&I