

# **Biomass Co-firing Strategies: Economical Methods to Achieve Renewable Energy Goals**

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# Today's Agenda

- Co-firing Methods
- Co-firing Experience
- Advantages and Technical Concerns of Co-firing
- Impacts of Co-firing on Emissions
- Economics of Co-firing



# Co-firing Methods

## ● Direct Co-firing Methods

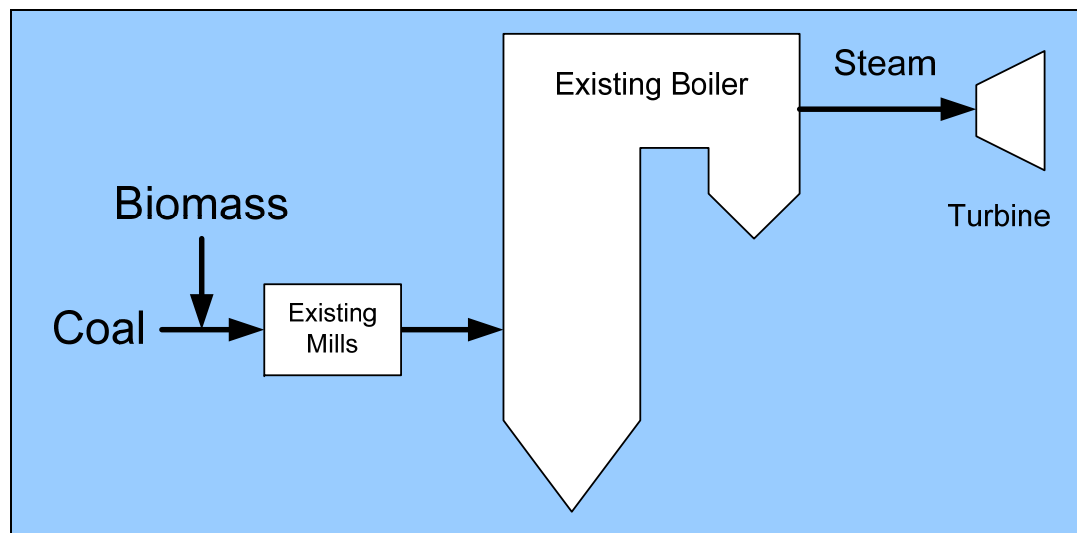
- Solid biomass combusted with coal in existing boiler systems
- Examples include:
  - Fuel Blending
  - Separate Injection

## ● Indirect Co-firing Methods

- Solid biomass processed in a separate combustor or reactor, with products of the process utilized in existing thermal systems
- Examples include:
  - Separate Combustion
  - Pyrolysis – primary product: bio-oil
  - Gasification – primary product: syngas

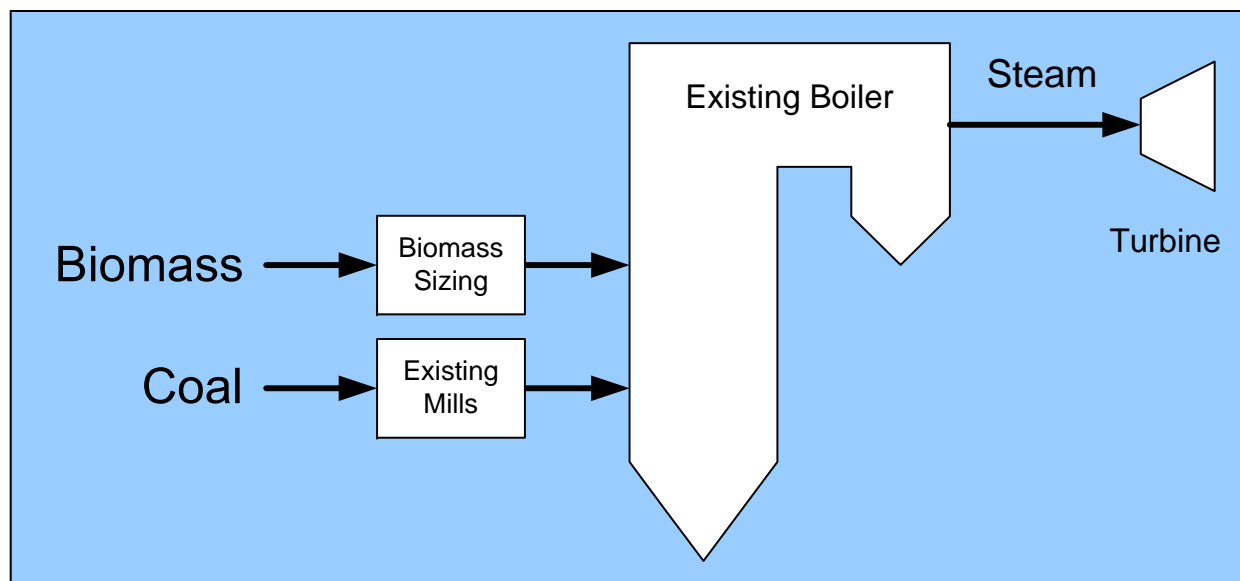
# Co-firing Methods – Fuel Blending

- Mixing of coal and biomass prior to injection into the boiler
  - Mixed on existing fuel pile via mobile equipment
  - For pulverized coal systems, fuel blending results in co-milling of fuels in existing pulverizers
- Simplest and least expensive method of co-firing
- Limits of co-firing via fuel blending:
  - PC boilers: 2% to 3% (by heat input)
  - Cyclone and FB boilers: 10% to 20% (heat input)



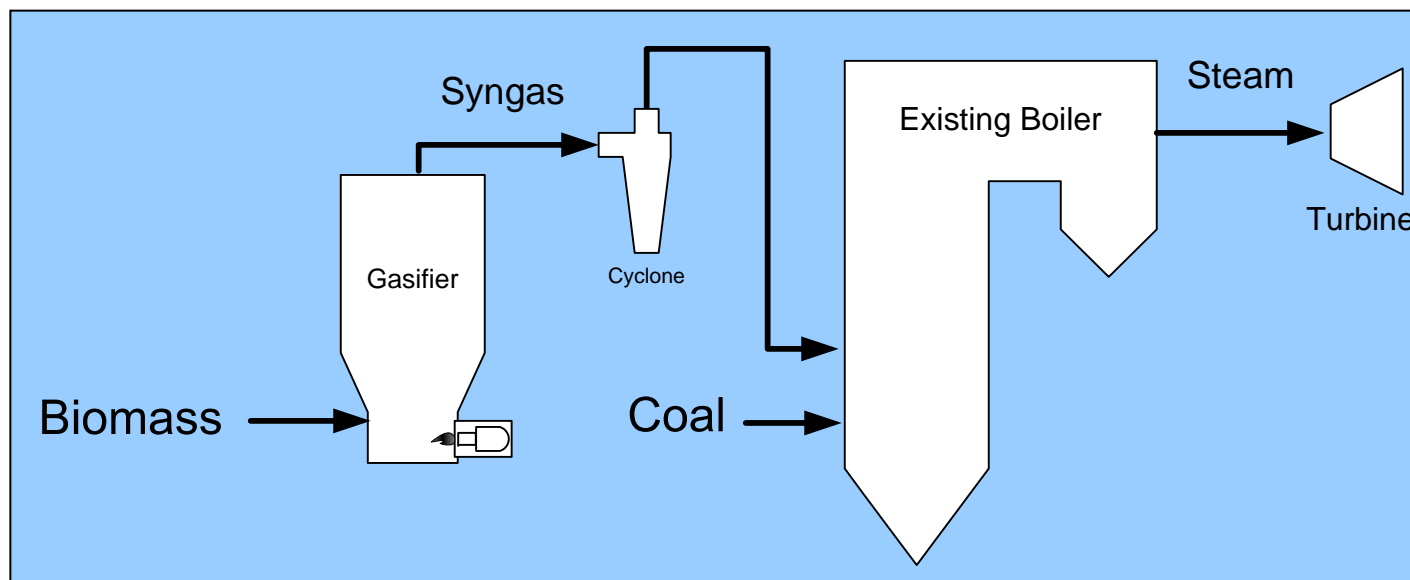
## Co-firing Methods – Separate Injection

- Requires separate biomass handling system and boiler modification
- Allows biomass to provide greater proportion of heat input:
  - For PC units: 10% or greater
  - For cyclone or fluidized bed units: 20% or greater



## Co-firing Methods – Indirect Co-firing via Gasification

- Reduces quantity of biomass ash introduced into existing boiler systems (by perhaps 60%)
- Syngas may be utilized as a NO<sub>x</sub> re-burning fuel
- Significantly higher capital costs relative to direct co-firing



# Selected Co-firing Experience in the United States

- Direct co-firing methods
  - Very few utility units currently co-fire
    - One example: AES Greenidge
      - 108 MW tangentially fired PC boiler
      - Co-fires waste wood
      - Biomass may provide up to 10% by heat input
    - Ottumwa (Alliant)
      - 725 MW tangentially fired PC boiler
      - Test burn of switchgrass in 2006
      - Roughly 3% of heat input
  - Most utility-scale experience obtained during DOE co-firing demonstrations
    - Demonstrations conducted in late 1990's
    - Considered technically successful



# Experience in the U.S. – DOE Demonstrations

<b>DOE Sponsored Utility Cofiring Demonstrations.</b>						
<b>Utility and Plant</b>	<b>Boiler Capacity and Type</b>	<b>Biomass Heat Input (max) (%)</b>	<b>Biomass Type</b>	<b>Average Moisture (%)</b>	<b>Coal Type</b>	<b>Biomass Feeding</b>
TVA Allen	272 MW cyclone	10	Sawdust	44	Illinois Basin, Utah bituminous	Blending biomass and coal
TVA Colbert	190 MW wall-fired	1.5	Sawdust	44	Eastern bituminous	Blending biomass and coal
NYSEG Greenidge	108 MW tangential	10	Wood waste	30	Eastern bituminous	Separate injection
GPU Seward	32 MW wall-fired	10	Sawdust	44	Eastern bituminous	Separate injection
MG&E Blount St.	50 MW wall-fired	10	Switch-grass	10	Midwest bituminous	Separate injection
NIPSCO Mich. City	469 MW cyclone	6.5	Urban wood waste	30	PRB, Shoshone	Blending biomass and coal
NIPSCO Baily	194 MW cyclone	5-10	Wood waste	14	Illinois, Shoshone	Blending (trifire)
Allegheny Willow Island	188 MW cyclone	5-10	Wood	N/A	Eastern bituminous	Blending (trifire)
Allegheny Allbright	150 MW tangential	5-10	Ground wood	N/A	Eastern bituminous	Separate injection

Source: Paul Grabowski, "Biomass Cofiring." Accessed online at: <http://www.brdisolutions.com/site%20docs/PGCofiring.pdf>.

## Experience in the U.S. – DOE Demonstrations

- Key findings from DOE demonstrations include:
  - Separate injection system preferred over fuel blending
  - Co-milling may significantly impact pulverizer performance and O&M
  - Boiler efficiency and net plant heat rate not significantly affected
  - Woody fuels co-fired for extended periods without adverse effects
  - Alkalis present in herbaceous fuels (e.g., agricultural residues) may adversely affect boiler systems during prolonged co-firing

# Selected Co-firing Experience in the United States

- Gasification methods
  - McNeil Generating Station
    - Biomass feed rate: 200 dry tons per day
    - Syngas combusted in existing 50 MW boiler
    - Gasification system can provide roughly 15% of heat input to boiler
  - Xcel Energy – Bay Front conversion
    - Bay Front capacity: 76 MW
    - Solid biomass utilized as the primary fuel in 2 of 3 existing boilers
    - Xcel has announced plans to convert all boilers to fire biomass-derived syngas (currently scheduled to be completed late 2012)
    - Not a co-firing project, but technology would be demonstrated for other potential gasification co-firing projects



# Technical Considerations – Advantages and Incentives

- Advantages of co-firing
  - Provides baseload renewable power
  - Most efficient utilization of biomass for power generation
  - For regions with limited wind and solar options, biomass may be only practical renewable resource
- Technical Incentives
  - With separate injection, co-firing may recover boiler capacity for mill-limited or feed system-limited units
  - May present opportunities to beneficially dispose of waste streams (e.g., biosolids)

# Technical Considerations – Barriers

- Logistics of fuel supply and delivery:
  - Co-firing capacity limited by the quantity of biomass within given geographic area
  - Fuel deliveries for 25 MW project: 20 to 25 trucks per day
- Technical Concerns and Barriers
  - Alkali content of biomass fuels
    - Corrosion of heat transfer surfaces
    - Agglomeration of fluidized beds
  - Co-firing may preclude ash sales
    - Existing specification (ASTM C618) requires 100% coal ash
    - Significant revenue stream for many facilities
  - Co-firing may impact SCR systems (catalyst poisoning)
  - Plant management and staff often hesitant to make significant modifications to existing equipment and operations



# Impacts of Co-firing on Unit Emissions

- Emissions during co-firing of biomass and coal depend on fuel properties and the unit-specific combustion dynamics
- Co-firing test burns required to determine actual impacts
- In general, however:
  - Carbon dioxide (CO<sub>2</sub>)
    - Actual CO<sub>2</sub> emissions at the stack increase slightly due to slight decrease in unit efficiency
    - CO<sub>2</sub> emissions from biomass fuels are considered carbon neutral
    - Adjusted CO<sub>2</sub> emissions are reduced by slightly less than the proportion of heat input provided by biomass

## Impacts of Co-firing on Unit Emissions (cont.)

- Sulfur dioxide ( $\text{SO}_2$ )
  - Biomass typically contains little sulfur relative to coal
  - Emissions of  $\text{SO}_2$  anticipated to be reduced by proportion of heat input provided by biomass
- Nitrogen dioxide ( $\text{NO}_x$ )
  - Most biomass fuels contain less fuel-bound nitrogen than coal
  - Emissions of  $\text{NO}_x$  anticipated to be reduced by proportion of heat input provided by biomass
  - Effect on  $\text{NO}_x$  emissions less certain than  $\text{CO}_2$  and  $\text{SO}_2$  – boiler combustion dynamics may alter this effect
  - Re-tuning of the combustion process may be required to achieve appropriate combustion dynamics

# Economics of Co-firing – Capital Costs

- Total capital costs depend upon:
  - Method of co-firing
  - Size of co-firing system (i.e., MW of co-firing capacity)
  - Level of automation in biomass handling systems
  - Site layout and space constraints:
    - Routing of conveyors/handling equipment within site confines
    - Distance from biomass processing area to boiler systems
- For a given size:
  - Fuel blending is least capital intensive
  - Gasification is most capital intensive

# Economics of Co-firing – Representative Capital Costs

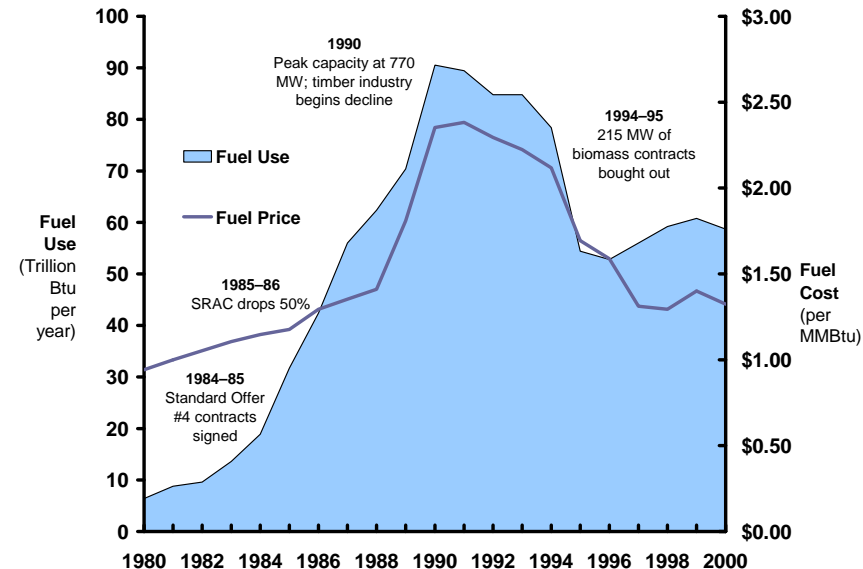
Method	Capital Cost (\$/kW) based on Co-firing System Size		
	10 MW	25 MW	40 MW
Fuel Blending	1,000 to 1,500	800 to 1,200	600 to 1,000
Separate Injection	1,300 to 1,800	1,000 to 1,500	700 to 1,100
Gasification	2,500 to 3,500	2,000 to 2,500	1,800 to 2,300

## Notes:

- (1) Capital costs presented are all-in EPC costs (excluding Owner's costs).
- (2) For 10 MW systems, it is assumed that mobile equipment would be employed to handle material to the extent possible. For 40 MW systems, it is assumed that automated stacking and reclaiming equipment would be employed.

# Economics of Co-firing – Impacts on O&M Costs

- Incremental non-fuel O&M costs associated with co-firing systems are small relative to O&M costs of overall plant
- Installation of biomass handling systems likely requires additional laborers in fuel yard
- If co-firing precludes ash sales, O&M costs associated with ash disposal will increase
- Biomass fuel costs:
  - Key driver for any biomass project
  - In many areas, biomass markets are immature, and price fluctuations may occur



Source: California Energy Commission

## Economics of Co-firing – Costs of Aux Power

- Co-firing systems require some auxiliary power
  - Primarily biomass sizing and pneumatic convey equipment
  - For 20 to 40 MW of co-firing capacity, equipment may require 2 to 3 MW of aux power
  - Smaller systems require greater percentage of aux power
- Replacement power cost
  - Utilities must operate at increased load on other units or purchase replacement power to offset aux load
  - Replacement power cost: \$80/MWh to \$120/MWh
  - Other renewables require additional spinning reserve

# Economics of Co-firing – Representative Costs of Co-firing vs. Other Renewables

- Direct co-firing options are lowest cost when compared to other large-scale options such as wind and solar

<b>Technology</b>	<b>Nominal Size (MW)</b>	<b>Total Project Costs (\$/kW)</b>	<b>Total Non-fuel O&amp;M (\$/MWh)</b>
Co-firing – Fuel Blending	25	600 to 1,000	10 to 15
Co-firing – Separate Injection	25	1,000 to 1,500	18 to 22
Wind	100	2,000 to 2,300	22 to 24
Co-firing - Gasification	25	2,000 to 2,500	20 to 25
Solar PV – Flat Plate	10	4,250 to 4,750	23 to 27
Biomass Standalone	35	4,500 to 5,500	27 to 33
Solar Thermal – Trough <sup>(1)</sup>	100	6,500 to 7,000	20 to 25
Notes:			
(1) Solar Thermal costs are provided for a facility with 6 hours of thermal storage.			

## Conclusions regarding Biomass Co-firing

- Co-firing is a technically viable renewable option
  - Successfully demonstrated around the world
  - Most significant challenge may be buy-in of plant staff
- Most efficient use of biomass resources
- Among lowest cost options for renewable projects greater than 25 MW in size
  - 25% to 50% of the cost of solar projects
  - Competitive with wind projects
- Specific project costs dependent upon design and condition of existing coal facilities
- As with any biomass project, cost of biomass fuel is likely the key economic parameter for the project