Natural gas processing plants typically consume natural gas to generate steam for mechanical power and process heating use. In western Canada, these plants remove hydrogen sulphide and carbon dioxide and extract hydrocarbon liquids from the incoming raw natural gas. These plants are sometimes located remotely in Forest Management Areas. Such locations are key to the concept of installing a biomass power plant at a natural gas processing plant. Harvesting of local wood waste to supply this boiler could be economically viable.

A high-pressure biomass-fired power boiler and a back-pressure steam turbine generator would replace the duty of the natural gas-fired power boilers in the gas processing plant. The back-pressure steam turbine would exhaust into the existing steam system. Internal natural gas consumption used for steam generation would be eliminated, imported power would be reduced, and there would be a net reduction in greenhouse gas emissions.

DEREK McCANN

ADDING A BIOMASS-FIRED COGENERATION POWER PLANT TO A NATURAL GAS PROCESSING PLANT

INTRODUCTION

In western Canada, there are several natural gas processing plants. These plants treat raw or sour natural gas and make it “sweet”. They remove hydrogen sulphide and carbon dioxide and extract hydrocarbon liquids from the raw gas. These processing plants are sometimes located within Forest Management Areas (FMAs).

A typical natural gas processing plant consumes sweet natural gas to generate steam for mechanical-drive turbines and process heat.

It is proposed to install a high-pressure biomass-fired power boiler and steam turbine generator that would replace the duties of the natural gas-fired power boilers and superheater and reduce imported electrical power in the gas processing plant.

A cogeneration plant is proposed where the natural gas processing plant would be the “steam host”.

PROJECT OBJECTIVES

There are several project objectives:

Use Locally Available Wood Waste - The haulage cost of wood waste is essentially a function of collection radius. With the natural gas processing plant located within a Forest Management Area, the collection radius would be minimized.

Eliminate In-house Natural Gas Consumption - The in-house natural gas-fired power boilers and superheater would no longer be required. The new biomass-fired power boiler would be capable of the full steaming rate on natural gas alone. This would be available in case there was a breakdown of the biomass handling system.

Reduce Imported Power Consumption - The new back-pressure steam turbine generator would generate most of the electrical power required by the natural gas processing plant.

Reduce Greenhouse Gases Due to Natural Gas Consumption - The biomass-fired power boiler would produce low levels of greenhouse gases (GHGs), and natural gas consumption would be eliminated.

Reduce Greenhouse Gases Associated with Local Imported Power Generation - Reduction of local imported power would reduce its associated GHGs.

Create an Acceptable Return on Investment (ROI) on Project Capital Using All Available Federal and Provincial Government Incentives for Greenhouse Gas Reductions - For the project to be economically viable, all available federal and provincial incentives for GHG reductions would have to be used.

DESCRIPTION OF EXISTING NATURAL GAS PROCESSING PLANT STEAM SYSTEM

The existing natural gas processing plant steam system is an example of cogeneration in which mechanical rather than electrical power is generated. It includes several
back-pressure mechanical-drive turbines driving pumps and one condensing mechanical-drive steam turbine driving a compressor.

Saturated high-pressure (HP) steam is generated at 2500 kPa(g) using natural gas-fired power boilers and a sulphur-plant waste heat boiler. Saturated low-pressure (LP) steam is consumed at 380 kPa(g). A natural gas-fired superheater is used to provide the HP steam supply to the condensing steam turbine.

The steam system is shown in Fig. 1.

**SELECTION OF INLET STEAM CONDITIONS FOR THE STEAM TURBINE GENERATOR**

It is proposed to install a “topping” back-pressure steam turbine generator (STG). In this arrangement, the steam turbine exhaust pressure would essentially match (allowing for pressure drop) the pressure in the processing plant’s HP steam system. Therefore, the inlet pressure to the steam turbine generator must be somewhat higher than 2500 kPa(g). To select the STG inlet conditions, a comparison was performed for three alternative cases; the results are shown in Table 1.

Overall efficiency is the product of the isentropic and the mechanical and electrical efficiencies.

Alternative C was selected because it had the highest power generation output. The economics of scale usually favour the largest plant. However, the cycle efficiencies of the three alternatives are somewhat similar.

**Mechanical-Drive Turbines**

At the natural gas processing plant, there are several mechanical-drive turbines, but no steam turbine generators. In pulp mills, mechanical-drive turbines are often replaced by electric motors because they are inefficient compared to steam turbine generators. For this potential project, replacing the various mechanical-drive turbines (MDTs) in the processing plant was considered. The overall efficiencies of the existing turbines were evaluated; the results are shown in Fig. 2.

It was found that small drives (~1000 HP) had low overall efficiencies (<50%). This is the case with fan drives on power and recovery boilers in pulp mills. However, large drives (>6000 HP) had good overall efficiencies (>70%). (A modern steam turbine generator has an overall efficiency of ~80%, depending on its size). Because there are many large drives in the existing processing plant, converting them would provide little benefit. Based on this, it was decided not to consider changing the mechanical drives.

**Cogeneration Gross Cycle Efficiency**

Cogeneration gross cycle efficiency can be defined as:

\[ \text{Gross Cycle Efficiency} = \left( \frac{E + H}{F} \right) \times 100 \]

where  
E is gross power output,  
H is net process heat,  
F is fuel energy (HHV basis),

and \[ H = Q_{\text{OUT}} - Q_{\text{IN}} \]

where \( Q_{\text{OUT}} \) is total heat exported and \( Q_{\text{IN}} \) is total heat returned.
**Biomass Cogeneration Options**

There are two biomass cogeneration options:
- Maximum cycle efficiency using a back-pressure turbine generator;
- Maximum power using a condensing steam turbine generator.

The two options were found to have the energy characteristics shown in Table 2.

The biomass fuel is assumed to have a moisture content of 35% (wet basis).

The condensing STG option would permit power export, but at a higher capital cost than the back-pressure STG option. It was decided to pursue the back-pressure STG option.

**Proposed Biomass Power Plant**

The proposed biomass power plant would include:
- A biomass-fired power boiler operating at 10,340 kPa(g) and 508°C
- An electrostatic precipitator to limit particulate matter emissions
- A biomass handling system
- An ash handling system
- A back-pressure steam turbine generator
- A new de-aerator
- A new make-up water treatment plant
- Piping tie-ins to existing systems
- Electrical tie-ins to existing systems
- A new boiler and steam turbine building.

**INTEGRATION OF THE NEW BIOMASS POWER PLANT AND THE EXISTING NATURAL GAS PROCESSING PLANT STEAM SYSTEM**

The integration of the new biomass power plant and the existing natural gas processing plant steam system is shown in Fig. 3.

**Energy Impacts of the Proposed Biomass-fired Power Plant**

The energy impacts of the proposed biomass-fired power plant are shown in Table 3.

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**TABLE 2**  
Energy characteristics.

<table>
<thead>
<tr>
<th>STG Option</th>
<th>Units</th>
<th>Back-Pressure</th>
<th>Condensing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation</td>
<td>MW</td>
<td>12.4</td>
<td>42.4</td>
</tr>
<tr>
<td>Cycle Efficiency</td>
<td>%</td>
<td>74</td>
<td>24</td>
</tr>
</tbody>
</table>

---

---
The plant electrical load will increase due to the biomass power plant auxiliaries. The imported electrical load has dropped significantly. Natural gas consumption has disappeared.

Greenhouse Gas Reductions

The following greenhouse gas (GHG) emissions were considered:

- Carbon dioxide (CO$_2$)
- Methane (CH$_4$)
- Nitrous oxide (N$_2$O).

These were totalled as CO$_2$ equivalent using global warming potential (GWP) [1]. The annual reductions are summarized in Table 4.

The imported-power GHG emissions intensity was assumed to be for Alberta (see [1]), which has several coal-fired power plants. The other GHG intensities used can be found in Reference 1.

Economics of Biomass Power Plants

The total cost of generated electricity includes the following components:

- Capital recovery cost
- Fuel cost
- Operations and maintenance cost.

These costs are usually evaluated on a $/MWh basis.

The capital recovery cost depends on the amount of capital debt, the interest rate, and the repayment period. It is usually expressed as a percentage of the project capital cost. The capital cost of a biomass-fired power plant is significant compared to other types of power plants. Therefore, the capital recovery cost would be significant.

The fuel cost would include the costs of harvesting and transporting the biomass. Biomass fuel costs are strongly influenced by the radius of the collection area. Biomass fuel has high moisture content, which results in low cogeneration cycle efficiency. A greater quantity of wet biomass than of dry biomass is required to produce the same steam flow (because boiler thermal efficiency drops with increasing biomass moisture content).

The operations and maintenance cost would include labour and materials.

Economics of scale would apply; a large plant would have lower total power costs than a small plant. Consequently, it can be difficult to make small biomass power plants economically attractive.

One method to improve the project economics is to obtain as many GHG reduction grants as possible from the federal and provincial governments. These grants can be of critical importance in determining the viability of a project. It would also help if the generated power could be sold as “biomass” power because biomass power can be sold for more than $100/MWh. This is higher than the price of power from traditional fuels.

Most projects require an internal rate of return (IRR) of 18% to be economically viable. Current low natural gas prices (~$3.00/GJ) mean that it is difficult to make a project viable.

UNIQUE OPPORTUNITY FOR COOPERATION BETWEEN THE OIL AND GAS AND THE FOREST INDUSTRIES

This project could provide a unique opportunity for cooperation between the oil and gas and the forest industries. A forest industry company could provide the biomass, and an oil and gas company could act as steam host. This arrangement could provide economic benefits to both companies while significantly reducing GHG emissions for the common good.

REFERENCES


### Table 3

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Units</th>
<th>Existing Plant</th>
<th>Existing Plant with Biomass Power Plant</th>
<th>Increment</th>
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<tbody>
<tr>
<td>Electrical Load</td>
<td>MW</td>
<td>15.5</td>
<td>16.5</td>
<td>+1.0</td>
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<tr>
<td>Generation</td>
<td>MW</td>
<td>0</td>
<td>12.4</td>
<td>+12.4</td>
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<tr>
<td>Imported Load</td>
<td>MW</td>
<td>15.5</td>
<td>4.1</td>
<td>-11.4</td>
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<tr>
<td>Annual Natural Gas Consumption</td>
<td>10$^6$ SCM/a</td>
<td>100</td>
<td>0</td>
<td>-100</td>
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<tr>
<td>Annual Biomass Consumption</td>
<td>BDt/a</td>
<td>0</td>
<td>241,500</td>
<td>+241,500</td>
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</table>

### Table 4

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Units</th>
<th>Baseline</th>
<th>Future</th>
<th>Reduction</th>
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<tbody>
<tr>
<td>Annual Natural Gas GHG Emissions</td>
<td>t CO$_2$eq/a</td>
<td>218,585</td>
<td>0</td>
<td>218,585</td>
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<tr>
<td>Annual Biomass Boiler GHG Emissions</td>
<td>t CO$_2$eq/a</td>
<td>0</td>
<td>7,180</td>
<td>(7,180)</td>
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<tr>
<td>Annual Biomass Harvesting GHG Emissions</td>
<td>t CO$_2$eq/a</td>
<td>0</td>
<td>4,735</td>
<td>(4,735)</td>
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<tr>
<td>Imported Power GHG Emissions</td>
<td>t CO$_2$eq/a</td>
<td>129,030</td>
<td>34,130</td>
<td>94,900</td>
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<tr>
<td><strong>Total</strong></td>
<td>t CO$_2$eq/a</td>
<td>347,615</td>
<td>46,045</td>
<td>301,570</td>
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