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ANNEXE 1

Mémoire présenté à :

Régie de l'Énergie Québec

DANS LE CADRE DES AUDIENCES SUR SON AVIS SUR LA SÉCURITÉ ÉNERGÉTIQUE DES QUÉBÉCOIS À L'ÉGARD DES APPROVISIONNEMENTS ÉLECTRIQUES ET LA CONTRIBUTION DU PROJET DU SUROÎT (DOSSIER R-3526-2004)

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Application of IGCC Technology in Canada – Phase IV

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INTRODUCTION

As the 2008-2012 time frame draws closer, the efforts of Canada (and the rest of the world) are increasingly focused on the best strategy for meeting climate change commitments under the Kyoto Protocol. The energy supply situation is probably unique in Canada due in part to the diversity of natural resources and the immense land mass within our borders. Because of the way in which the energy resources are distributed across the country, Alberta, Saskatchewan, Ontario, New Brunswick, and Nova Scotia have made massive investments in coal-fired utility power plants. While, particularly in Alberta and Saskatchewan, coal provides the cheapest means of generating electricity, the undeniable fact is that conventional coal burning is the most greenhouse gas-intensive method of power generation.

We are thus faced with a dilemma – more than half the population of Canada is inextricably tied to coal as the provider of much of the amenities of life. One analysis has suggested that Canada must reduce its coal-fired power production by 38% over the next decade, at a cost approaching $10 billion, in order to meet the Kyoto target, a lowering of GHG emissions by 6% from those of the baseline year of 1990. This, the analysis says, can be achieved through a shift to natural gas, biomass and hydro [1].

A major shift to natural gas in North America has already begun, with apparently disastrous consequences. The National Petroleum Council has estimated that 110 GW of new gas-fired generation will be added in the US by 2010, requiring 30% of total US gas consumption, and certain to keep pressure on supplies [2]. In addition to the already significant natural gas supply shortage/price increase, the lead time for purchase of utility-scale gas turbines has stretched to four years, making forward planning of new power supply more difficult. Deregulation (actual or planned) of the electricity supply and increasing gas prices have resulted in a sellers' market, with electricity prices up to US$1.50/kWh, frequent blackouts, and potential bankruptcy of a number of large electric companies (especially in California). [Note: Pacific Gas & Electric filed for bankruptcy protection on 2001 April 09]. In Alberta, the government has tried to soften the blow of deregulation-fed rate increases through more than $1 billion in energy rebates, and longstanding industries are working the midnight shift to avoid high daytime peak rates, or contemplating moving to other provinces to avoid bankruptcy. In British Columbia, Cominco has temporarily curtailed zinc production, because it can profit more by selling electricity to the US.

These examples serve to emphasize the consequences of trying to solve the GHG problem with a wholesale shift to natural gas electricity production. The authors feel strongly that, until the time comes when CO_2 capture is regulated or carbon taxes imposed, the emphasis with regard to GHG reduction should be on those more practical solutions that can remove a significant amount of CO_2 at reasonable cost. These practical solutions must, of necessity, include coal firing to protect the utilities' coal plant investment while restabilizing the electricity market.

Addressing the potentially enormous financial penalty to the coal-dependent provinces will require innovative, imaginative thinking. Fortunately, gasification and biomass fuels offer an opportunity to substantially whittle down the above 38% figure. Whereas gasification is proving to be a very efficient fuel conversion process, biomass is a desirable GHG-neutral fuel with, unfortunately, undesirable utilization problems, due mainly to its low energy density. Now, however, commercial experience is available in the gasification of biomass and the utilization of the produced fuel gas and char in a conventional coal-fired power plant.

What this achieves essentially is the "co-firing" of coal and biomass, while avoiding the handling and feeding problems associated with true co-firing in one boiler. Advantages of a plant of this type stem from the fact that the gasifier, usually an air-blown fluidized bed unit, is designed specifically for the available biomass fuel, while the existing PC unit requires very little modification. Whereas biomass combustion by itself usually achieves electricity generation efficiency in the 16-25% (HHV) range, the gasification/PC combination should achieve an overall efficiency very close to that of the PC unit, i.e., 32-36% (HHV). Further, SO_2 emissions are reduced by simple dilution and, depending on where the fuel gas is injected into the PC (as in gas reburning, for example), NO_x emissions can also be considerably reduced. Finally, as biomass and coal are combusted separately, separation of ash products is easily achieved. This is important where a market exists in the cement industry for coal ash, and there is potential for utilization of biomass ash as a fertilizer, for example.

Because the produced biomass fuel gas requires very little pretreatment prior to injection into the PC, the gasifier becomes relatively uncomplicated and thus relatively inexpensive. Since the FBC gasifier is inherently capable of handling low-quality, wet fuels (potentially of low or negative value, i.e., with a tipping fee), an opportunity for modest savings on the displaced coal also exists.

Taking this scheme to the extreme, and assuming suitable waste biomass quantities were available, if every operating Canadian PC unit was coupled to a biomass gasifier, it is estimated that close to one-half the required 38% reduction in coal-fired power production would be achieved, with a sizable CO_2 emissions reduction. (Note that in commercially operated plants of this type, typically 15-20% of the coal heating value is displaced by biomass-produced fuel gas).

STRATEGY

In Phase III of this project, we recommended that a watching brief in the field of IGCC was necessary and desirable to provide a comfortable degree of readiness should the indicators be favourable for IGCC in Canada in the future. In this phase, this objective has been addressed through literature reviews, conference attendance (1999 EPRI/GTC Gasification Conference, 2000 EPRI/GTC Gasification Conference, and Gasification 4: the Future) and appropriate site visits (Puertollano, Spain and Shell Pernis and Air Products Rozenburg, The Netherlands).

Phase III saw the development of a 20 MWe ASPEN biomass gasification model and its testing with various typically Canadian feedstocks. In the present phase, the model was reconfigured and improved to simulate the front end (a supplier of fuel gas) of a biomass gasifier/PC unit or a biomass offers a practical opportunity to reduce CO_2, NO_x and SO_2, while cutting coal use, for $1000/kW or less.

GASIFICATION EFFLUENTS

This short section is included at the request of Environment Canada. CETC has examined voluminous current literature and conference proceedings on operational plants and company projections, and reports the results from the small number of successful hits. While gaseous and solid effluents are generally comparable regardless of fuel and gasifier type, very little concrete information is available on liquid effluents, and we can only assume that projections and favourable results may be reported while unfavourable results are not. This section should, therefore, be read with this caveat in mind.

Gaseous Effluents

The Wabash River IGCC plant has reported airborne emissions statistics comparing pre- and post-repowering (IGCC) data [17]. The following values are listed in ng/J (pre/post): SO_2 – 1333/43; NO_x – 344/65; CO – 21/21; PM-10 – 30/nondetectable; and VOC – 1.3/1.3. The SO_2 data represent a reduction of 97%. The NO_x regulation (NSPS) has recently been revised to an output-based value of 0.73 kg/MWh of electric power generated, and the Wabash River figure is equivalent to 0.49 kg/MWh. For PM-10 the NSPS value is 12.9 ng/J and is easily met by the IGCC's performance.

For the Tampa Electric IGCC, SO_2 emissions are <65 ng/J (target was 116 ng/J); NO_x emissions are <116 ng/J (target was 116 ng/J); and PM-10 is <7.7 kg/h, the permitted limit [9].

Projections from the PIEMSA IGCC project (Bilbao, Spain) are (design/expected, mg/Nm^3): NO_x – <75/60; SO_2 – <45/15; CO – <100/30; and PM – <10/5, all based on dry flue gas at 15% O_2 [18].

The Shell Pernis IGCC reports that steam injection was installed on the gas turbines to meet the strict NO_x emissions regulations of 65 ng/J (as NO_2 at 15% O_2 in dry flue gas) [19].

Global Energy projects that acid gas cleanup and sulphur recovery units can remove greater than 99% of H_2S and COS from syngas produced by a BGL gasifier from solid hydrocarbon feedstocks [16].

Solid Effluents

Slag products of gasification are reported to contain the inorganic fraction of the feedstock in an environmentally benign, non-leachable form. This material has been approved for marketing for roadway base, roofing material, seawall construction aggregate and blasting grit [9, 16, 17, 19]. Work is currently in progress at the Tampa Electric IGCC on a slag handling system that can separate the unburned carbon for recycle, as an efficiency improvement (carbon burnout is only about 95%