ECONOMIC MODELING TO SUPPORT THE DEVELOPMENT OF CLIMATE CHANGE REGULATIONS

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1. Introduction

The release of greenhouse gases (GHG) and the resulting global climate change have gained considerable attention worldwide. Many scientists believe that human activities are responsible for almost all of the increase in greenhouse gases in the atmosphere over the last 150 years. Thus, all countries and jurisdictions are seeking GHG emission mitigation strategies to contribute climate-resilient pathways for sustainable development.

Economic production activity is an important direct and indirect source of GHG emissions. It is also a highly heterogeneous contributor that has different emission performances in various industrial sectors. Given the fact that the remaining potential for cost-effective emission reductions is still great, industrially related GHG legislation has been adopted in many regions all over the world, such as British Columbia, United States, and Europe. Legislation for specific industries can effectively reduce the GHG emissions, but it may also increase the production costs and hinder economic development to different extents. Economic activities are closely linked, with the legislation for one industry potentially affecting the economic activities of other industries.

Saskatchewan is experiencing booming economy along with the growth of GHG emissions. Nowadays, most of scientists believe that the GHG emissions contribute to increasing global temperatures, and the extreme weather events become more frequent as the result of climate change. Hence, management of GHG emissions is particularly important to reduce the extreme weather events. However, management of GHG emissions is a complex task due to many interactions among environmental, social and economic factors. In particular, this complexity may be further compounded due to the presence of various uncertainties in these factors. Thus, a computable general equilibrium (CGE) mode capable of effectively reflecting the uncertainties and interactions is desired for analyzing the economic impacts of specific climate policies and designing effective GHG policy frameworks.

A CGE model provides a consistent framework to analyze the economic impacts of a policy, including the direct and indirect effects of policy changes. Thus, the CGE model has been widely used to investigate the impacts of a carbon tax on socio-economic systems during the past several decades. Since a carbon tax has both macro and micro (economic) impacts, previous studies about carbon tax were conducted from different scopes, including global, national, regional, and industrial. Focused on different issues, CGE models adopt a range of factors as the primary production factors. For example, forest land services were considered as one of the production factors when analyzing the regional economic impacts of climate change and adaptation in the forest industries. Since most of the carbon emissions were caused by energy consumption, energy has been usually considered as a production factor in CGE models that are used to evaluate carbon tax effects.

Previously, a number of energy-environment-economic models were developed and applied in Canada, including simulation and optimization models. For example, the energy model can provide decision-making support for the energy systems through the optimization techniques. However, in the energy model, the impact of energy policy is restricted within the energy system. In the real world, the energy policy must affect the whole economic system.

Taking all of these challenges into consideration, the situation in Saskatchewan is complex and has serious technical and political considerations. Elected officials are eager to acquire scientific bases for decisions at multiple administrative and/or jurisdictional levels in terms of policies and strategies for carbon-emission reduction. Stakeholders in various industries are also seeking the most economical pathways under new policies and strategies. A vast number of conflicting objectives, interactive effects and compounded risks may co-exist within various sectors in the context of Saskatchewan. Thus, an in-depth and comprehensive study with regard to the carbon tax impacts on the socio-economic system of Saskatchewan will offer significant benefits.

Therefore, the objective of this project is to develop a Saskatchewan Computable General Equilibrium (SK-CGE) Model and explore feasible GHG-emission reduction approaches. In detail, the SK-CGE model will be applied to a market driven by multiple factors for estimating the impacts of different policies on the whole economy.

The report is structured as follows. In Section 2, the methodology and developed SK-CGE model with revenue recycling mechanism are introduced. We then discuss and analyze the model results in detail. The affordable penalty analysis of 14 companies is presented in Section 3. In Section 4, the analysis of real reduction ability of 8 industries is provided. In Section 5, we discussed the dynamic CGE model results in general. Lastly, the conclusions are reported in Section 6.

2. Methodology

2.1. Benefit-and-Cost Analysis

Benefit-and-Cost Analysis (BCA) is the process of quantifying costs and benefits of a decision, program, or project (over a certain period), and those of its alternatives (within the same period), in order to have a single scale of comparison for unbiased evaluation. Unlike the present value (PV) method of investment appraisal, BCA estimates the net present value (NPV) of the decision by discounting the investment and returns. Though employed mainly in financial analysis, a BCA is not limited to monetary considerations only. It often includes those environmental and social costs and benefits that can be reasonably quantified.

It is a systematic process for calculating and comparing benefits and costs of a project for two purposes: to determine if it is a sound investment (justification/feasibility) and to see how it compares with alternate projects (ranking/priority assignment). Analysis of BCA is an analysis that is used in the application of modern welfare economics and directed to improve the economic efficiency of resource allocation. Extended net present value or net present values are cost benefit analysis has been expanded from analysis of existing conventional benefits and costs before.

The first step in the process is to compile a comprehensive list of all the costs and benefits associated with the project or decision. Costs should include direct and indirect costs, intangible costs, opportunity costs and the cost of potential risks. Benefits should include all direct and indirect revenues and intangible benefits, such as increased production from improved employee safety and morale, or increased sales from customer goodwill. A common unit of monetary measurement should then be applied to all items on the list. Care should be taken to not underestimate costs or overestimate benefits. A conservative approach with a conscious effort to avoid any subjective tendencies when calculating estimates is best suited when assigning value to both costs and benefits for the purpose of a cost-benefit analysis.

The final step is to quantitatively compare the results of the aggregate costs and benefits to determine if the benefits outweigh the costs. If so, then the rational decision is to go forward with project. In not, a review of the project is warranted to see if adjustments can be made to either increase benefits and/or decrease costs to make the project viable. If not, the project may be abandoned.

The total discounted benefits are divided by the total discounted costs. Projects with a benefit-cost ratio greater than 1 have greater benefits than costs; hence they have positive *net* benefits. The higher the ratio, the greater the benefits relative to the costs. Note that simple benefit-cost ratio is insensitive to the magnitude of net benefits and therefore may favor projects with small costs and benefits over those with higher net benefits. (This problem can be eliminated by the use of the incremental benefit-cost ratio or the net present value.)

The simple Benefit-and-Cost Ratio can be calculated as follows:

$n+1$: the number of years over which benefits and costs are analyzed
B_i: the benefits of the project in year

C_i : the costs of the project in year
d : the discount rate

- First, discount the costs and benefits in future years.
- The discounted benefits of the project in year i are equal to $\frac{B_i}{(1+d)^i}$
- The discounted costs of the project in year i are equal to $\frac{C_i}{(1+d)^i}$
- Then, sum both the discounted benefits and the discounted costs over all years (0 though n) and divide the sum of the discounted benefits by the sum of the discounted costs:

$$\Sigma \frac{B_i}{(1+d)^i} / \Sigma \frac{C_i}{(1+d)^i} \text{, summed over } i = 0 \text{ to } n\text{.}$$

This procedure is mathematically equivalent to Net Present Value, and it always gives the same result, but use of this procedure may provide greater insights into the relationships between costs and benefits of the different projects.

2.2. Environmentally Extended Input-Output (EEIO) Model

2.2.1. The framework of the EEIO model

An Environmentally Extended Input-Output (EEIO) model was developed to facilitate the analysis of GHG emission intensities of different industries. The two main inputs of the proposed model are Input-Output (I-O) tables and the emission factors of various emission source sectors. According to the analysis objectives, the I-O table should be aggregated and disaggregated to fit the environmental satellite accounts. The disaggregation method should be chosen based on data availability and sector characteristics to ensure the accuracy of model inputs. The emission factors of different energy sources vary due to region and utilization. In-depth surveys and research are thus needed to obtain the emission factors for one specific region. After data collection and processing, detailed analysis and comparative analysis can be conducted to reveal the emission intensities of various industries and the interactions among them. The EEIO model is based on the Leontief framework. In this section, we first outline the I-O Leontief framework.

Consider an economy with $N+1$ sectors where each sector i produces a unique good. The total output of good i from the ith sector is noted x_i and the amount of good i that sector j consumes from sector i is noted z_{ij} . The total output x_i corresponds to the sum of the intermediate consumption by the economy and the final demand f_i, which can be formulated as:

$$x_i = \sum_{j=1}^{N} z_{ij} + f_i, \quad i = 1, 2, \cdots, N+1 \tag{2.1}$$

In the I-O Leontief framework, it is assumed that the industry flow from sector i to sector j depends linearly on the total output of sector j. If sector j needs a_{ij} units of good i to produce 1 unit of good j, Equation (2.1) can be rewritten as:

$$x_i = \sum_{j=1}^{N} a_{ij} x_{ij} + f_i, \quad i = 1, 2, \cdots, N+1 \tag{2.2}$$

Writing Equation (2.2) in matrix form and inverting the system leads to:

$$\boldsymbol{x} = (\boldsymbol{I} - \boldsymbol{A})^{-1} \times \boldsymbol{f} = \boldsymbol{L}\boldsymbol{f} \tag{2.3}$$

Where $\boldsymbol{A}$ is the technical coefficient matrix, i is the identity matrix of size $(N+1) \times (N+1)$ and $\boldsymbol{L}$ is the Leontief inverse matrix. The $ijth$ coefficient in the inverse Leontief matrix $\boldsymbol{L}$ represents the total requirement of goods from sector i to meet the final demand of sector j.

In order to perform the analysis of embodied CO_2 emissions per dollar of final demand for each sector, the Leontief matrix is multiplied by the CO_2 satellite account e, as shown in Equation (2.4).

$$\boldsymbol{\varepsilon} = \boldsymbol{e}(\boldsymbol{I} - \boldsymbol{A})^{-1} \tag{2.4}$$

Where the CO_2 satellite account $\boldsymbol{e}$ is a row vector whose size is identical to the Leontief inverse matrix. The components corresponding to the emission sources sector are the satellite emission factors and other matrix components are zero.

2.2.2. Transformation of the I-O table

Different countries use different formats for their I-O tables around the world, but a common format is the combined I-O table as Leontief first developed. In Canada, the I-O tables are three separate tables, including an output table, an input table, and a final demand table. Thus, a transformation must be done to get the common forms Industry-Industry I-O table and Commodity-Commodity I-O table. A step-by-step description of the transformation is given by below.

A mirror transition on negative numbers in the input table and output table was first conducted. If the z_{ij} in the input table is negative and its value is N, then the z_{ij} is adjusted to 0. Meanwhile, the z_{ij} in the Output table is modified by adding $-N$. The mirror transition for the Output table is done with the same method. Then, the total commodity output and total industry output are calculated by Equation (2.5) and Equation (2.6).

$$q_j = u_{j1} \ldots + u_{jn} + f_j \tag{2.5}$$

$$x_j = m_{1j} \ldots + m_{nj} \tag{2.6}$$

Where q is the total commodity output, u is the matrix in the input table, f is the final demand, x is the total industry output, and m is the matrix in the output table.

Next, technical coefficients for the industry-industry I-O table ($\boldsymbol{A}_{CC}$), which represent the input of commodity i to produce unit commodity j, and the commodity-commodity I-O table ($\boldsymbol{A}_{II}$), which represents the input of industry i to produce a unit in industry j, can be obtained using Equation (2.7) to Equation (2.10).

$$b_{ij} = u_{ij} / x_j \tag{2.7}$$

$$d_{ij} = m_{ij} / q_j \tag{2.8}$$

$$\boldsymbol{A}_{CC} = \boldsymbol{B} \times \boldsymbol{D}' \tag{2.9}$$

$$\boldsymbol{A}_{\text{II}} = \boldsymbol{D}' \times \boldsymbol{B} \tag{2.10}$$

Where b is the production coefficient for the commodity-commodity I-O table, which means the input of commodity i to produce per unit of industry j; d is the produce coefficient for industry-industry I-O table, which means the input of industry i needed to produce per unit commodity j; u_{ij} is the commodity i used in industry j; x_j is the total output of industry j; m_{ij} is the commodity j produced in industry i; q_j is the total output of commodity j.

The industry-industry I-O table ($\boldsymbol{IO}_{CC}$) and the commodity-commodity I-O table ($\boldsymbol{IO}_{\mathrm{II}}$) were calculated following the steps represented by Equation (2.11) to Equation (2.14). The final demand of the commodity-commodity I-O table is the data in the final demand table. The value added of the industry-industry I-O table is the value added in the input table.

$$\boldsymbol{IO}_{CC} = \boldsymbol{A}_{CC} \times diag(\boldsymbol{Q}) \tag{2.11}$$

$$\boldsymbol{IO}_{\mathrm{II}} = \boldsymbol{A}_{\mathrm{II}} \times diag(\boldsymbol{X}) \tag{2.12}$$

$$\boldsymbol{II}_{cc-va} = \boldsymbol{V} \times \boldsymbol{B} \tag{2.13}$$

$$\boldsymbol{IO}_{\mathrm{II}-fd} = \boldsymbol{D}' \times \boldsymbol{F} \tag{2.14}$$

Where $diag(\boldsymbol{Q})$ is the diagonal matrix of $\boldsymbol{Q}$; $diag(\boldsymbol{X})$ is the diagonal matrix of $\boldsymbol{X}$; $\boldsymbol{II}_{cc-va}$ is the value added of the commodity-commodity I-O table; $\boldsymbol{IO}_{\mathrm{II}-fd}$ is the final demand of the industry-industry I-O table.

2.2.3. Aggregation and disaggregation of the I-O table

The existing I-O table of Saskatchewan contains 35 sectors, as listed in Table 1. Although aggregation of some types of industries may have only a minor effect on the overall economy displayed in an I-O table, the aggregation of sectors with a high impact on the environment has important consequences. For instance, the “mining, quarrying, and oil and gas extraction” sector contains “oil extraction”, “gas extraction”, and “coal mining”, which are significantly different in input requirements, outputs, and emission factors. Another example is the electricity sector, where CO_2 emissions associated with a unit of output from fossil fuels are very different from those of a unit of output from renewable energy sources. But all generation units are generally combined in one sector (i.e. utility) in the I-O table. Moreover, in order to simplify the calculation process, some sectors were aggregated in this report due to their consistency in emission-related activities, such as the ten public administration related sectors.

Table 1. The aggregation and disaggregation of Input-Output table sectors

IO TABLE	MODEL	ABBREVIATION
Crop and animal production	Crop and animal production	CAP
Forestry and logging	Forestry and logging	FRL
Fishing, hunting and trapping	Fishing, hunting and trapping	FHT
Support activities for agriculture and forestry	Support activities for agriculture and forestry	SAA
Mining, quarrying, and oil and gas extraction	Oil extraction Gas extraction Coal mining Other mining, quarrying	OEX GEX CAM OMQ
Utilities	Fossil-fuel electric power generation Clean electric power generation Natural gas distribution Other utilities	FFE CEE NGD OTU
Residential building construction Non-residential building construction Engineering construction Repair construction Other activities of the construction industry	Construction	CON
Manufacturing	Petroleum refineries Other manufacturing	PER OTM
Wholesale trade Retail trade	Trade	TRA
Transportation and warehousing	Transportation Warehousing and storage	TRP WAS
Information and cultural industries Finance, insurance, real estate, rental and leasing and holding companies Owner occupied dwellings Professional, scientific and technical services Administrative and support, waste management and remediation services Educational services Health care and social assistance Arts, entertainment and recreation Accommodation and food services Other services (except public administration)	Services	SER
Repair, maintenance and operating and office supplies Advertising, promotion, meals, entertainment, and travel Transportation margins Non-profit institutions serving households Government education services Government health services Other federal government services Other provincial and territorial government services Other municipal government services Other aboriginal government services	Public administration	PUB

According to Saskatchewan's environmental-economic conditions, the I-O table used in this report was further disaggregated and aggregated into 20 sectors, as listed in Table 1. All combustion-related emission resources have been disaggregated to facilitate the GHG emission intensity analysis, including coal, crude oil, petroleum products, non-marketable natural gas, and marketable natural gas. Other sectors that are sensitive to the raw emission sources have also been disaggregated, such as the transportation, fossil-fuel electricity power generation, and clean electricity power generation. Ten service related sectors and ten public administration related sectors have been aggregated into a combined service sector and a combined public administration sector.

Based on the Leontief framework, the technical coefficient matrix ***A*** has been used to aggregate and disaggregate the I-O table. When aggregating several sectors, the technical coefficients can be added easily. When disaggregating one sector to several sectors, different methods should be adopted according to the available information and the sectors' characteristics. In this report, due to data limitations and research objectives, the input coefficients, output coefficients, and intra matrix have been determined following Wolsky and Marriot.

The input coefficients, which indicates in what proportion the common sectors supply the new sectors, have been determined using Equation (2.15).

$$a^*_{i,N+k} = r_k a_{i,N+1}, \qquad i = 1, 2, \cdots, N \tag{2.15}$$

The output coefficients have been determined using Equation (2.16), indicating in what proportion the common sectors purchase from the new sectors.

$$a^*_{N+k,i} = w_k a_{N+1,i}, \qquad k = 1, 2, \cdots, n, \quad i = 1, 2, \cdots, N \tag{2.16}$$

The construction of the intra-industry matrix indicates in what proportion the new sectors supply and purchase from the new sectors. The intra-industry value is split among each entry in the new intra-matrix by multiplication with the row and column weight factor.

Specially, some exceptions needed to be considered when disaggregating the upstream energy production to downstream energy transmission. For instance, all purchases from the fossil fuel sector (e.g. crude oil, marketable natural gas) are most likely made by the fossil-fuel electricity generation sector. Also, the outputs of raw energy extraction sectors should be allocated mainly to the energy transfer sectors. Therefore, the input coefficients and output coefficients of the related energy sectors into the new sectors have been made. Results of the manual allocation are shown in Table 2.

Table 2. Manual allocation of input coefficients

	FFE	CEE	NGD	OTU	PER	OTM	TRP	WAS
OEX	0.08948	0	0.01315	0.01217	0.00251	0	0.003025	0.001389
GEX	0	0	0.00451	0	0.00007	0.00003	0.000119	5.46E-05
CAM	0.00684	0	0.00101	0.00093	0.00013	0.00006	0.000231	0.000106
NGD	0.00025	0	0.00005	0.00005	0.00169	0.00081	0.001199	0.00055
PER	0.00947	0	0.00139	0.00129	0.08157	0.00041	0.0086	0.002962

2.2.4. Emission factors

The emission factors e_i quantify the embodied emissions of GHG per Canadian dollar from the five emission source sectors. Table 3 presents the numerical values used in this report. The emission factors were taken from Statistics Canada, NIR, EPA, and other references. In order to perform the emission intensity analysis for each sector, the emission factors needed to be converted into emissions per Canadian dollar. This was done using the mean price of emission sources, which were taken from Statistics Canada, SaskEnergy annual report, SaskPower report, and other data. The GHG emissions consider CO_2, CH_4 and N_2O. The CO_2 equivalent emission intensities of different sectors were then calculated using Equation (2.17).

$$Ef_{GHG} = Ef_{CO_2} + 25 \times Ef_{CH_4} + 298 \times Ef_{N_2O} \tag{2.17}$$

Table 3. Emission factors

	CO_2 Scenario		GHG Scenario (CO_2, CH_4 and N_2O)	
Coal	1465 g/kg	32555.6 g/C$	1474 g/kg	32765 g/C$
Crude Oil	2718 g/L	3928 g/C$	2727 g/L	3941 g/C$
Petroleum Products	2557 g/L	2055 g/C$	2624 g/L	2109 g/C$
Non-marketable Natural Gas	1829 g/m^3	6088 g/C$	1907 g/m^3	6350 g/C$
Marketable Natural Gas	2441 g/m^3	8266 g/C$	2618 g/m^3	8869 g/C$

In Saskatchewan, there is more than one type of emission sources, such as refined petroleum products. Even for one product, the emission factors for different utilizations are different. For example, the CH_4 emission factor for coal used in electric utilities is 0.02 g/kg, while the value will be changed to 4 g/kg for residential and public administration use. When calculating the emission factors for the five emission sources, the emission factors given by NIR and the supply and demand table given by Statistics Canada have been adopted. The weighted sum was then used as the emission factor of the emission source. The emission factors for CO_2 and GHG are shown as followings:

$$\boldsymbol{e}_1 = (0, 0, 0, 0, 3928.236, 6088.265, 32555.6, 0, 0, 0, 8266.73, 0, 0, 2055.6, 0, 0, 0, 0, 0, 0) \tag{2.18}$$

$$\boldsymbol{e}_2 = (0, 0, 0, 0, 3941.25, 6350.636, 32765.33, 0, 0, 0, 8869.141, 0, 0, 2109.949, 0, 0, 0, 0, 0, 0) \tag{2.19}$$

2.3. Saskatchewan Computable General Equilibrium (SK-CGE) Model

In order to support the development of climate change regulations, various policy-induced general welfare impacts need to be simulated and compared. As is well known, Computable General Equilibrium (CGE) models are a class of economic models that use actual economic data to estimate how an economy might react to changes in terms of policy, technology or other external factors. Therefore, a Saskatchewan Computable General Equilibrium (SK-CGE) model was developed to achieve better simulation results.

2.3.1. Development of SK-CGE model

The CGE models have been proven to be effective for policy analysis. Many models such as DREAM, BEAR and TERM have been applied successfully in the world. However, there are no specific CGE models for Canada, let alone Saskatchewan. In this project, one specific CGE model for Saskatchewan (SK-CGE) was developed. The development and application process is shown in Figure 1.

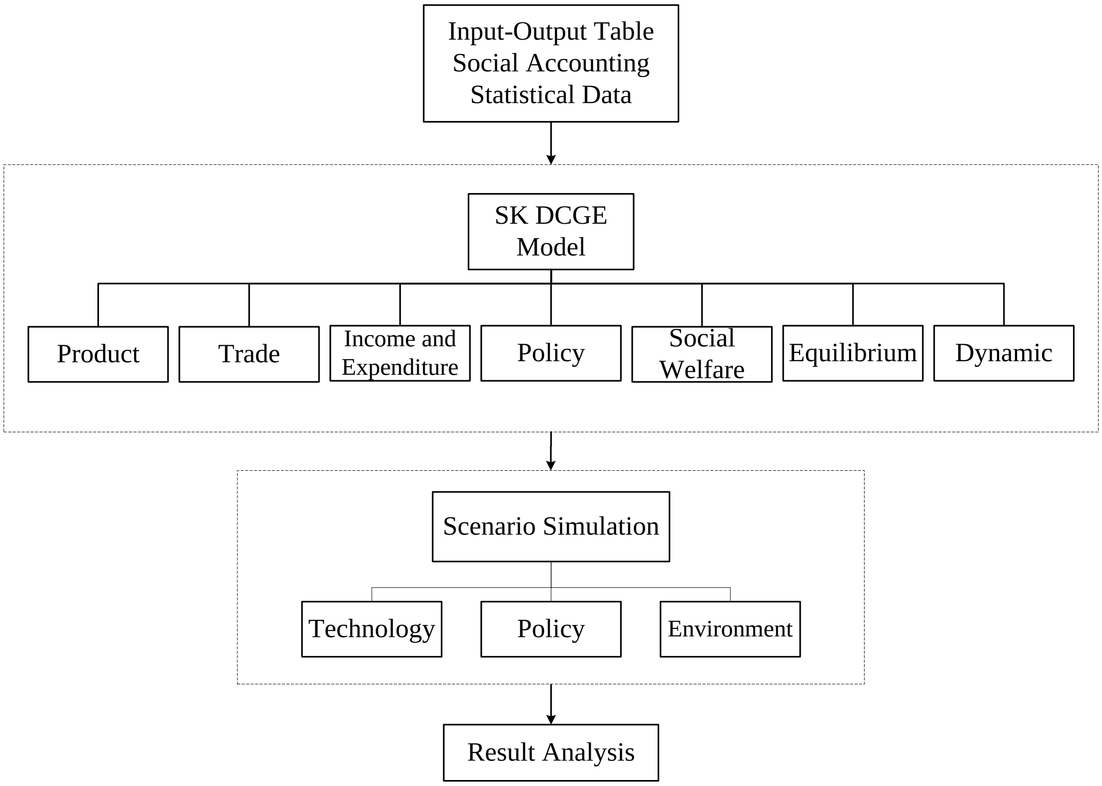


Figure 1. The flowchart of SK-CGE model

2.3.1.1. Data collection and preparation

All related data with respect to the provincial energy, environmental, and socio-economic systems was collected through a series of wide-range literature, public investigations, and systematical calculations. The data was further classified into four aspects, i.e. Input-Output (IO) Table, social accounting matrix, statistic data, and policy scenarios. In particular, as the central data, the GHG emissions produced from energy consumption, agriculture fermentation, waste disposal and industrial processes was specifically collected and analyzed.

Subsequently, the raw data was re-calculated, organized, and calibrated. The IO table from the Statistic Canada was separated as the industry-product Input and Output tables. These tables were transformed to the classic IO tables in the period of 1990 to 2014, which were later applied to extend the social accounting matrix.

Then, on the basis of the energy use pattern in Saskatchewan, the IO tables were further aggregated and disaggregated by using the bio-proportional scaling (RAS) methods. Elasticity parameters and other coefficients used in the SK-CGE model were calibrated through conducting a history match. These tables of elasticity parameters and other coefficients include: (a) intermediate input coefficients, (b) the amount of capital used elastic coefficient and per capital resources, (c) coefficients of consumption function, (d) income and expenditure parameters, (e) resources parameters and (f) environmental parameters.

2.3.1.2. Model development and calibration

The SK-CGE model was developed on the basis of data mentioned above. Generally, it comprises product module, trade module, income and expenditure module, social welfare module, dynamic module, equilibrium module, and policy module.

The production module describes the ways in which capital, labor, energy, and intermediate inputs can be used to produce outputs. This module is represented by nested separable linear homogeneous constant elasticity of substitution (CES) production functions.

In this model, there are nine types of production inputs, i.e. capital, labor, coal, crude oil, petroleum, natural gas, thermal power, clean power and intermediate inputs. Various production inputs are combined to produce final goods. Specifically, coal, crude oil, petroleum and natural gas are aggregated into fossil fuel energies, while thermal power and clean power are aggregated into electric power. Then, fossil fuel energies and electric power are aggregated into energy composites. Furthermore, energy composites and capital composites are aggregated into capital-energy composites. The labor-capital-energy composites and intermediate inputs are aggregated into final outputs. A Constant Elasticity of Substitution (CES) function has been applied to represent the resource inputs, and its mathematical expression is shown in Equation 3.1.

$$QX_i = \alpha_i^a \left(\delta_i^a F_i^{\frac{\sigma-1}{\sigma}} + \left(1-\delta_i^a\right) E_i^{\frac{\sigma-1}{\sigma}} \right)^{\frac{\sigma}{\sigma-1}} \tag{3.1}$$

Where

QX_i represents total output;

α_i^a represents a scale parameter in the CES activity function;

δ_i^a represents a CES activity function share parameter;

F_i E_i represents two kinds of inputs;

σ represents the elasticity substitution parameter in CES activity function;
i represents production activity sets.

In the trade module, given types of commodities are both exported and imported simultaneously. To address the two-way trade problem, the Armington assumption has been adopted by treating imported commodities and domestic commodities as differentiated products. For domestic goods and imports, the CES utility function has been used to determine their domestic demands, as shown in Equation 3.2.

$$QQ_j = \alpha_j^q \left(\delta_j^q QM_j^{-\rho_i^q} + \left(1 - \delta_j^q\right) QD_j^{-\rho_j^q} \right)^{\frac{1}{\rho_j^q}} \tag{3.2}$$

Where

QQ_j represents the composite supply;

α_j^q represents a scale parameter in the CES utility function;

δ_j^q represents a CES utility function share parameter

QM_j represents the imported commodities quantity;

QD_j represents the domestic commodities quantity;

ρ_i^q represents the CES utility function exponent, which is calculated by elasticity substitution parameters;

j represents the commodity sets that are both imported and produced domestically.

When making a choice between supplying the domestic market and exporting, a Constant Elasticity Transformation (CET) function has been adopted, as shown in Equation 3.3. This equation describes the allocation of marketed domestic output.

$$QT_k = \alpha_k^t \left(\delta_k^t QE_k^{\rho_k^t} + \left(1 - \delta_k^t\right) QD_k^{\rho_k^t} \right)^{\frac{1}{\rho_k^t}} \tag{3.3}$$

Where

QT_k represents the composite supply;

α_k^t represents a scale parameter in the CES utility function;

δ_k^t represents the CES utility function share parameter

QE_k represents the exported commodities quantity;

QD_k represents the domestic commodities quantity;

ρ_k^t represents the CES utility function exponent, which is calculated by the elasticity substitution parameters;

k represents the commodity sets that are both exported and produced domestically.

The income and expenditure module describes income and expenditure changes of different economic entities. Four types of economic agents are considered in this study, including households, enterprises, the government and the rest of the world.

The household incomes come from labor, capital, and transfer payments from government, enterprises and the rest of the world. For expenditures, the household satisfy their commodities demand, invest on capital, and save the rest of their incomes. The consumption function satisfies the assumption of the Stone-Geary utility function, as shown in Equation 3.4.

$$DH_i \cdot P_i = \gamma_i \cdot P_i + \beta_i \left(YH - \sum_i \gamma_i \cdot P_i \right) \tag{3.4}$$

Where

DH_i represents the household demand for commodity i;

P_i represents the market price of commodity i;

γ_i represents the subsistence consumption level of commodity i;

YH represents the total income of household;

β_i represents the marginal propensity of consumption of commodity i;

i represents the commodity sets.

The incomes of enterprise come from capital. The incomes were used for paying the labor fee, indirect tax, and investment for further production. The incomes of government are composed of household income taxes, enterprise income taxes, tariffs, indirect taxes, income from capital and transfer payments from the rest of the world. Specially, the government will gain income from carbon tax after the carbon tax module has been introduced. The government expenditure contains commodity consumption and transfer payments to households.

The model assumes that CO_2 emissions related to a given fossil fuel are proportional to its quantity. The carbon tax imposed on fossil fuels is based on their content of CO_2 and is modeled as an excise tax. The tax increases the cost of using fuels and induces firms to reduce their use through substitution effects. The magnitude of the increase in the production cost depends on several factors among which are the energy intensity of the firm and the ease of substitution among inputs. The carbon tax is considered as one of the income streams for government in this study. The carbon tax levied on each fossil energy and the ad valorem duty rate are calculated by Equation 3.5 and Equation 3.6.

$$CTAX_f = t_c QQ_f \varepsilon_f \tag{3.5}$$

$$t_{cf} = \frac{CTAX_f}{PQ_f QQ_f} \tag{3.6}$$

Where

$CTAX_f$ represents a carbon tax levied on fossil energy f;

t_c represents the specific duty rate of the carbon tax;

t_{cf} represents the ad valorem duty rate of carbon tax on fossil energy f;

QQ_f represents the total domestic consumption of on fossil energy f;

ε_f represents the carbon emission coefficient of fossil energy f;

PQ_f represents the price of fossil energy f;

f represents the fossil energy sets.

In accordance with the General Equilibrium theory, a CGE model refers to the combination of factor market balance and commodity market balance at the same time. In the equilibrium module, there are three kinds of macro-equilibrium and three kinds of micro-equilibrium, including exchange equilibrium, input and output equilibrium, income and expenditure equilibrium, resources market clearing, capital market clearing, and products market clearing. The income and expenditure equilibrium means all the economic entities' expenditures equals their revenue. Both income and expenditure covers the transfer payments from and to other entities. The inputs and outputs equilibrium requires each industry's total supply to meet the aggregate of intermediate demand, domestic consumption, net export, and investment. Capital market clearing means the savings of all sectors to match the total investments.

2.3.2. Application of SK-CGE model

In this project, the SK-CGE model was modified to follow the changes in the real world. Various policy scenarios, national and international economic drivers and other changes were considered through changing the model codes and data streams.

The policy module in the SK-CGE model was added and changed when simulating different policy scenarios. The possible policies for reducing GHG emissions were absolutely included, for example, (a) carbon tax, (b) carbon cap-and-trade, (c) set targets for main emission industries, and so on. New technologies and resources shortage were also covered in the policy module, such as (a) improvement of capacity factor for one power generation technology, (b) application of wind combination in the natural gas-fired plants, (c) reduction of costs of the wind power plants or solar power plants due to one technology, (d) rise of natural gas price, and (e) shortage of water resource in Saskatchewan.

In addition, the national and international economic drivers were reflected in the SK-CGE model. Saskatchewan is the second net oil exporter and its agricultural products account for 90% in Canada. The economy of Saskatchewan has a close relationship with the national economy all the time. Hence, any change caused from the national and international trade policies was also reflected in the policy module of SK-CGE model. The above applications were achieved through data resetting and recoding. The TABLO language and the GAMs are two of the most powerful and convenient tools to solve the above-mentioned problems and are easily understood and operated. Such tools can provide great convenience for achievement of applying results.

3. Affordable Penalty Analysis

3.1. Affordable penalty analysis of Mosaic

Table 4. Affordable penalty summary of Mosaic

Year	Total Output (million C$)	Total Benefit (million C$)	Total Emissions (tonne)
2014	3413.37	1105.07	826710
2015	2862.99	922.31	840930
2016	1984.24	302.05	766800

Note: total output here is total net sales.

Table 5. Emission penalty under different scenarios of Mosaic

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	302.05	766800	7.68	2.5%
20 C$/tonne	302.05	766800	15.36	5.1%
30 C$/tonne	302.05	766800	23.04	7.6%
40 C$/tonne	302.05	766800	30.72	10.2%
50 C$/tonne	302.05	766800	38.4	12.7%

The Mosaic Company is the world's leading producer and marketer of concentrated phosphate and potash crop nutrients. They are the largest integrated phosphate producer in the world and one of the largest producers and marketers of phosphate-based animal feed ingredients in North America. They are one of the four largest potash producers in the world. Through their broad product offering, they are a single source supplier of phosphate- and potash-based crop nutrients and animal feed ingredients. They serve customers in approximately 40 countries. They mine phosphate rock in Florida and process rock into finished phosphate products at facilities in Florida and Louisiana. They mine potash in Saskatchewan and New Mexico. They have other production, blending or distribution operations in Brazil, China, India and Paraguay, as well as strategic equity investments in a phosphate rock mine in the Bayovar region in Peru and a joint venture formed to develop a phosphate rock mine and chemical complexes in the Kingdom of Saudi Arabia. Their distribution operations serve the top four nutrient-consuming countries in the world: China, India, the United States and Brazil.

The Mosaic Company is a Delaware corporation that was incorporated in March 2004 and serves as the parent company of the business that was formed through the October 2004 combination of IMC Global Inc. and the fertilizer businesses of Cargill, Incorporated. They are publicly traded on the New York Stock Exchange under the ticker symbol "MOS" and are headquartered in Plymouth, Minnesota.

They conduct their business through wholly and majority-owned subsidiaries as well as businesses in which they own less than a majority or a non-controlling interest. They are organized into three reportable business segments: Phosphates, Potash and International Distribution. Intersegment eliminations, mark-to-market gains/losses on derivatives, debt expenses, Stream song Resort® results of operations and their legacy Argentina and Chile results are included within Corporate, Eliminations and Other.

They are one of the four largest potash producers in the world They mine and process potash in Canada and the United States and sell potash throughout North America and internationally, principally as fertilizer, but also for use in industrial applications and, to a lesser degree, as animal feed ingredients. They account for approximately 12% of estimated global annual potash production and 39% of estimated North American annual potash production.

The term "potash" applies generally to the common salts of potassium. Muriate of potash ("MOP") is the primary source of potassium for the crop nutrient industry. Red MOP has traces of iron oxide. The granular and standard grade Red MOP products are well suited for direct fertilizer application and bulk blending. White MOP has a higher percent potassium oxide ("K2O"). White MOP, besides being well suited for the agricultural market, is used in many industrial applications. They also produce a double sulfate of potash magnesia product, which they market under their brand name K-Mag®, at their Carlsbad, New Mexico facility.

Their potash products are marketed worldwide to crop nutrient manufacturers, distributors and retailers and are also used in the manufacturing of mixed crop nutrients and, to a lesser extent, in animal feed ingredients. They also sell potash to customers for industrial use. In addition, their potash products are used for de-icing and as a water softener regenerant. In 2016, they operated three potash mines in Canada, including two shaft mines with a total of three production shafts and one solution mine, as well as one potash shaft mine in the United States. They also own related refineries at each of the mines.

They continue the expansion of capacity in their Potash segment with the K3 shafts at their Esterhazy mine, which are expected to begin mining potash ore in 2017 and following ramp-up to add an estimated 0.9 million tonnes to their annual potash operational capacity. This will provide for an infrastructure to move ore from K3 to the K1 and K2 mills, giving them the flexibility to optimize production at K1, K2 and K3 in order to mitigate risk from current and future brine inflows. It is possible that the costs of remedial efforts at Esterhazy may further increase in the future and that such an increase could be material, or, in the extreme scenario, that the brine inflows, risk to employees or remediation costs may increase to a level which would cause them to change their mining processes or abandon the mines. See “Key Factors that can Affect Results of Operations and Financial Condition” and “Potash Net Sales and Gross Margin” in their Management’s Analysis and “Their Esterhazy mine has had an inflow of salt saturated brine for more than 30 years” in Part I, Item 1A, “Risk Factors” in this report, which are incorporated herein by reference, for a discussion of costs, risks and other information relating to the brine inflows. The map below shows the location of each of their potash mines.

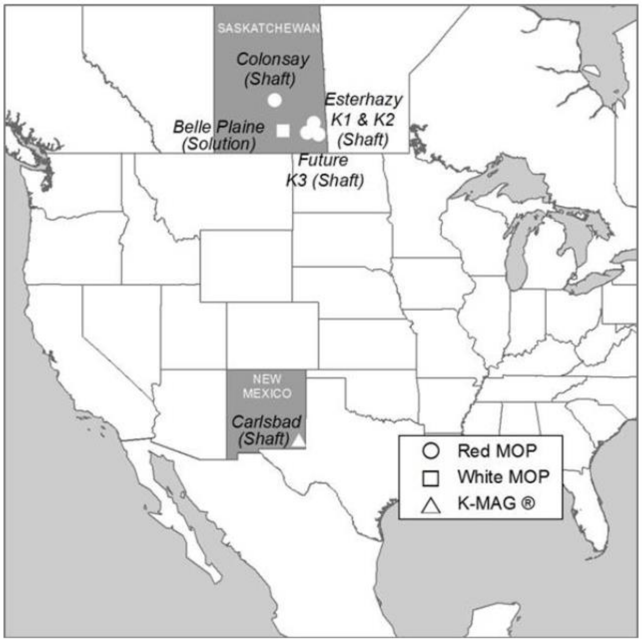
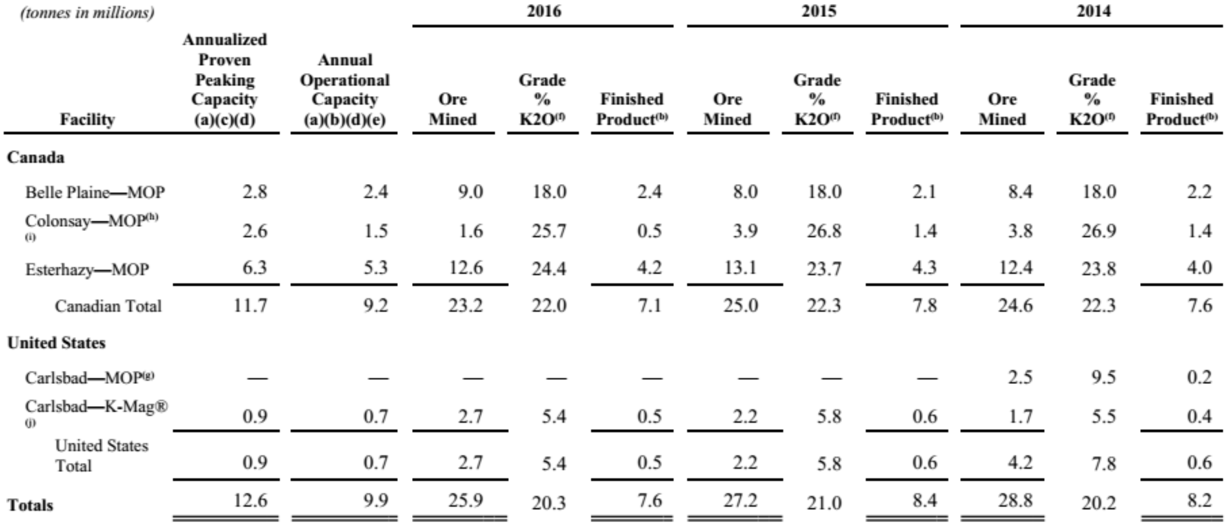


Figure 2. Locations of Potash mines

(Their current potash annualized operational capacity totals 9.9 million tonnes of product per year and accounts for approximately 14% of world annual capacity and 43% of North American annual capacity. Production during 2016 totaled 7.6 million tonnes. They account for approximately 12% of estimated world annual production and 39% of estimated North American annual production.)

Table 6. Annual capacity, annual capacity, average grade and finished product output of each Potash mines for years 2016, 2015 and 2014



(tonnes in millions)			2016			2015			2014		
Facility	**Annualized Proven Peaking Capacity (a)(c)(d)**	**Annual Operational Capacity (a)(b)(d)(e)**	**Ore Mined**	**Grade % K2O(f)**	**Finished Product(b)**	**Ore Mined**	**Grade % K2O(f)**	**Finished Product(b)**	**Ore Mined**	**Grade % K2O(f)**	**Finished Product(b)**
Canada											
Belle Plaine—MOP	2.8	2.4	9.0	18.0	2.4	8.0	18.0	2.1	8.4	18.0	2.2
Colonsay—MOP(h)(i)	2.6	1.5	1.6	25.7	0.5	3.9	26.8	1.4	3.8	26.9	1.4
Esterhazy—MOP	6.3	5.3	12.6	24.4	4.2	13.1	23.7	4.3	12.4	23.8	4.0
Canadian Total	11.7	9.2	23.2	22.0	7.1	25.0	22.3	7.8	24.6	22.3	7.6
United States											
Carlsbad—MOP(g)	—	—	—	—	—	—	—	—	2.5	9.5	0.2
Carlsbad—K-Mag®(j)	0.9	0.7	2.7	5.4	0.5	2.2	5.8	0.6	1.7	5.5	0.4
United States Total	0.9	0.7	2.7	5.4	0.5	2.2	5.8	0.6	4.2	7.8	0.6
Totals	12.6	9.9	25.9	20.3	7.6	27.2	21.0	8.4	28.8	20.2	8.2

(a) Finished product.

(b) Actual production varies from annual operational capacity shown in the above table due to factors that include among others the level of demand for their products, maintenance and turnaround time, the quality of the reserves and the nature of the geologic formations they are mining at any particular time, accidents, mechanical failure, product mix, and other operating conditions.

(c) Represents full capacity assuming no turnaround or maintenance time.

(d) The annualized proven peaking capacity shown above is the capacity currently used to determine their share of Canpotex, Limited ("Canpotex") sales. Canpotex members' respective shares of Canpotex sales are based upon the members' respective proven peaking capacities for producing potash. When a Canpotex member expands its production capacity, the new capacity is added to that member's proven peaking capacity based on a proving run at the maximum production level. Alternatively, after January 2017, Canpotex members may elect to rely on an independent engineering firm and approved protocols to calculate their proven peaking capacity. The annual operational capacity reported in the table above can exceed the annualized proven peaking capacity until the proving run has been completed. Effective January 1, 2014, their share of Canpotex sales was 42.5%. Subsequently, one of Canpotex's other members demonstrated an increase in its capacity, which resulted in lowering their share of Canpotex sales to 38.8%, effective July 1, 2014. Effective January 1, 2015, their share of Canpotex sales increased to 40.6%, as a result of a proving run of their expansion of their Colonsay mine, which was successfully completed in 2014. Effective January 1, 2016, their share of Canpotex sales decreased to 38.1%, as Canpotex's other members demonstrated a change in capacity.

(e) Annual operational capacity is their estimated long term potash capacity based on the quality of reserves and the nature of the geologic formations expected to be mined, milled and/or processed over the long term, average amount of scheduled down time, including maintenance and scheduled turnaround time, and product mix, and no significant modifications to operating conditions, equipment or facilities. Operational capacities will continue to be updated to the extent new production results impact ore grades assumptions.

(f) Grade % K2O is a traditional reference to the percentage (by weight) of potassium oxide contained in the ore. A higher percentage corresponds to a higher percentage of potassium oxide in the ore.

(g) Effective December 28, 2014, they permanently discontinued production of MOP at their Carlsbad facility.

(h) In July 2016, they temporarily idled their Colonsay, Saskatchewan potash mine for the remainder of 2016 in light of reduced customer demand while adapting to challenging potash market conditions. They resumed production in January 2017.

(i)They have the ability to reach an annual operating capacity of 2.1 million tonnes over time by increasing their staffing levels and investment in mine development activities.

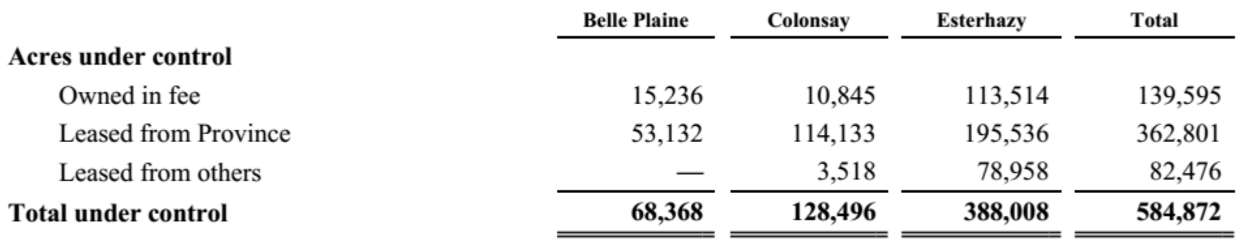
(j) K-Mag® is a specialty product that they produce at their Carlsbad facility. In 2014, they reduced their annual operational capacity of their K-Mag® due to lower ore grades.

They operate three Canadian potash facilities all located in the southern half of the Province of Saskatchewan, including their solution mine at Belle Plaine, two interconnected mine shafts at their Esterhazy shaft mine and their shaft mine at Colonsay.

Extensive potash deposits are found in the southern half of the Province of Saskatchewan. The potash ore is contained in a predominantly rock salt formation known as the Prairie Evaporites. The Prairie Evaporites deposits are bounded by limestone formations and contain the potash beds. Three potash deposits of economic importance occur in Saskatchewan: the Esterhazy, Belle Plaine and Patience Lake members. The Patience Lake member is mined at Colonsay, and the Esterhazy member at Esterhazy. At Belle Plaine all three members are mined. Each of the major potash members contains several potash beds of different thicknesses and grades. The particular beds mined at Colonsay and Esterhazy have a mining height of 11 and 8 feet, respectively. At Belle Plaine several beds of different thicknesses are mined.

Their potash mines in Canada produce MOP exclusively. Esterhazy and Colonsay utilize shaft mining while Belle Plaine utilizes solution mining technology. Traditional potash shaft mining takes place underground at depths of over 1,000 meters where continuous mining machines cut out the ore face and load it onto conveyor belts. The ore is then crushed, moved to storage bins and hoisted to refineries above ground. In contrast, their solution mining process involves heated brine, which is pumped through a "cluster" to dissolve the potash in the ore beds at a depth of approximately 1,500 meters. A cluster consists of a series of boreholes drilled into the potash ore. A separate distribution center at each cluster controls the brine flow. The solution containing dissolved potash and salt is pumped to a refinery where sodium chloride, a coproduct of this process, is separated from the potash through the use of evaporation and crystallization techniques. Concurrently, the solution is pumped into a cooling pond where additional crystallization occurs and the resulting product is recovered via a floating dredge. Refined potash is dewatered, dried and sized. Their Canadian operations produce 13 different MOP products, including industrial grades, many through proprietary processes. Their potash mineral rights in the Province of Saskatchewan consist of the following:

Table 7. Potash mineral rights in Saskatchewan



	Belle Plaine	Colonsay	Esterhazy	Total
Acres under control				
Owned in fee	15,236	10,845	113,514	139,595
Leased from Province	53,132	114,133	195,536	362,801
Leased from others	—	3,518	78,958	82,476
Total under control	**68,368**	**128,496**	**388,008**	**584,872**

They believe that their mineral rights in Saskatchewan are sufficient to support current operations for more than a century. Leases are generally renewable at their option for successive terms, generally 21 years each, except that certain of the acres shown above as “Leased from others” are leased under long-term leases with terms (including renewals at their option) that expire from 2023 to 2170.

They pay Canadian resource taxes consisting of the Potash Production Tax and resource surcharge. The Potash Production Tax is a Saskatchewan provincial tax on potash production and consists of a base payment and a profits tax. They also pay a percentage of the value of resource sales from their Saskatchewan mines. In addition to the Canadian resource taxes, royalties are payable to the mineral owners in respect of potash reserves or production of potash. They have included a further discussion of the Canadian resource taxes and royalties in their Management’s Analysis.

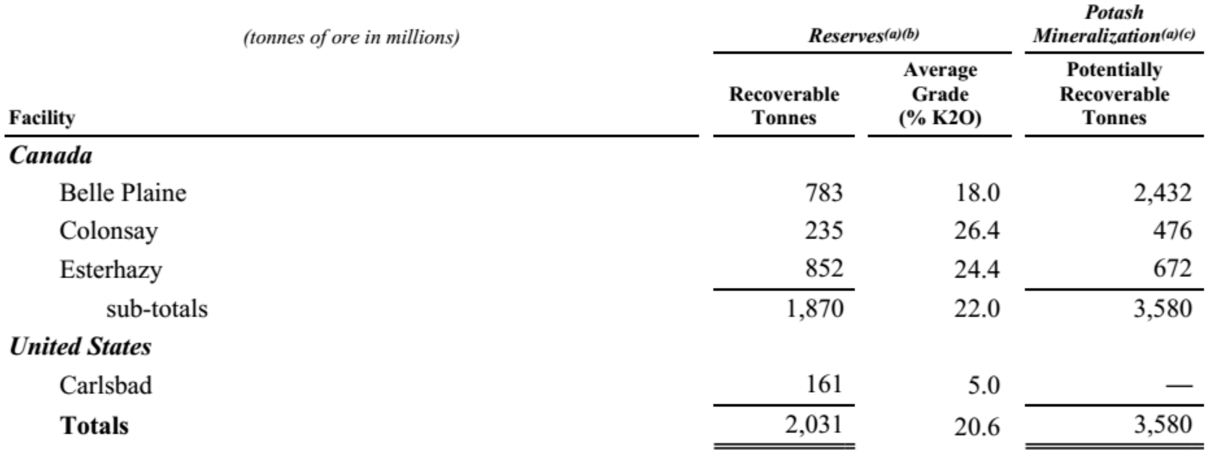
Since December 1985, they have effectively managed an inflow of salt saturated brine into their Esterhazy mine. At various times since then, they have experienced changing amounts and patterns of brine inflows at Esterhazy. To date, the brine inflow, including their remediation efforts to control it, has not had a material impact on their production processes or volumes. The volume of the net brine inflow (the rate of inflow less the amount they are pumping out of the mine) or net outflow (when they are pumping more brine out of the mine than the rate of inflow) fluctuates and is dependent on a number of variables, such as the location of the source of the inflow; the magnitude of the inflow; available pumping, surface and underground brine storage capacities; underground injection well capacities, and the effectiveness of calcium chloride and cementatious grout used to reduce or prevent the inflows, among other factors. As a result of these brine inflows, they incur expenditures, certain of which have been capitalized and others that have been charged to expense, in accordance with accounting principles generally accepted in the United States of America.

It is possible that the costs of remedial efforts at Esterhazy may further increase in the future and that such an increase could be material, or, in the extreme scenario, that the brine inflows, risk to employees or remediation costs may increase to a level which would cause them to change their mining processes or abandon the mine. The K3 shafts at their Esterhazy mine are part of their potash expansion plan, which is also designed to mitigate risk from current and future inflows.

Due to the ongoing brine inflow at Esterhazy, subject to exceptions that are limited in scope and amount, they are unable to obtain insurance coverage for underground operations for water incursion problems. Like other potash producers’ shaft mines, their Colonsay, Saskatchewan, and Carlsbad, New Mexico, mines are also subject to the risks of inflow of water as a result of their shaft mining operations, but water inflow risks at these mines are included in their insurance coverage subject to deductibles, limited coverage terms and lower sub-limits negotiated with their insurers.

Their estimated recoverable potash ore reserves and non-reserve potash mineralization as of December 31, 2016 for each of their mines are as follows:

Table 8. Estimated recoverable potash ore reserves and non-reserve potash mineralization



(tonnes of ore in millions)	*Reserves(a)(b)*		*Potash Mineralization(a)(c)*
Facility	**Recoverable Tonnes**	**Average Grade (% K2O)**	**Potentially Recoverable Tonnes**
Canada			
Belle Plaine	783	18.0	2,432
Colonsay	235	26.4	476
Esterhazy	852	24.4	672
sub-totals	1,870	22.0	3,580
United States			
Carlsbad	161	5.0	—
Totals	2,031	20.6	3,580

As discussed more fully above, they either own the reserves and mineralization shown above or lease them pursuant to mineral leases that generally remain in effect or are renewable at their option, or are long-term leases. Accordingly, they expect to be able to mine all reported reserves that are leased prior to termination or expiration of the existing leases.

Potash is a commodity available from several geographical regions around the world and, consequently, the market is highly competitive. Through their participation in Canpotex, they compete outside of North America against various independent and state-owned potash producers. Canpotex has substantial expertise and logistical resources for the international distribution of potash including strategically located export assets in Portland, Oregon, St. John, New Brunswick, and Vancouver, British Columbia. Their principal methods of competition with respect to the sale of potash include product pricing, and offering consistent, high-quality products and superior service. They believe that their potash cost structure is competitive in the industry and should improve as they continue to complete their potash expansion projects.

Table 9. Potash net sales, gross margin, sales volumes and certain other information

(in millions, except price per tonne or unit)	Years Ended December 31,			2016-2015		2015-2014	
	2016	2015	2014	Change	Percent	Change	Percent
Net sales:							
North America	$ 1,024.3	$ 1,337.9	$ 1,778.9	$ (313.6)	(23.4)%	$ (441.0)	(24.8)%
International	661.4	1,109.1	1,072.7	(447.7)	(40.4)%	36.4	3.4 %
Total	1,685.7	2,447.0	2,851.6	(761.3)	(31.1)%	(404.6)	(14.2)%
Cost of goods sold	1,429.1	1,658.7	1,928.4	(229.6)	(13.8)%	(269.7)	(14.0)%
Gross margin	256.6	788.3	923.2	(531.7)	(67.4)%	(134.9)	(14.6)%
Gross margin as a percentage of net sales	15.2%	32.2%	32.4%				
Canadian resource taxes (CRT)	101.1	248.0	168.4	(146.9)	(59.2)%	79.6	47.3 %
Gross margin (excluding CRT)[(a)]	$ 357.7	$ 1,036.3	$ 1,091.6	$ (678.6)	(65.5)%	$ (55.3)	(5.1)%
Gross margin (excluding CRT) as a percentage of net sales[(a)]	21.2%	42.3%	38.3%				
Sales volume (in thousands of metric tonnes)							
Crop Nutrients:							
North America	3,231	2,431	3,601	800	32.9 %	(1,170)	(32.5)%
International[(b)]	3,993	4,824	4,639	(831)	(17.2)%	185	4.0 %
Total	7,224	7,255	8,240	(31)	(0.4)%	(985)	(12.0)%
Non-agricultural	554	671	732	(117)	(17.4)%	(61)	(8.3)%
Total Potash Segment Tonnes	7,778	7,926	8,972	(148)	(1.9)%	(1,046)	(11.7)%
Average selling price per tonne (FOB plant):							
MOP - North America[(c)]	$ 174	$ 313	$ 325	$ (139)	(44.4)%	$ (12)	(3.7)%
MOP - International	158	239	226	(81)	(33.9)%	13	5.8 %
MOP - Average[(d)]	176	273	279	(97)	(35.5)%	(6)	(2.2)%
Production volume (in thousands of metric tonnes)	7,596	8,410	8,165	(814)	(9.7)%	245	3.0 %

The Potash segment's net sales decreased to $1.7 billion for the year ended December 31, 2016, compared to $2.4 billion in the same period a year ago. The decrease was primarily due to significantly lower average selling prices that resulted in a decrease in net sales of approximately $810 million. Although overall sales volumes were down in 2016 compared to the 2015, the current year sales mix resulted in a favorable impact on net sales of approximately $50 million, as they had an increase in their North America sales where prices were higher than international prices.

Their average MOP selling price was $176 per tonne for the year ended December 31, 2016, a decrease of $97 per tonne compared with the same period a year ago due to the factors discussed in the Overview.

The Potash segment's sales volumes decreased to 7.8 million tonnes for the year ended December 31, 2016, compared to 7.9 million tonnes in the same period a year ago driven by a decrease in International sales volumes, due to delays in settlement of the China and India contracts in 2016. This was partially offset by an increase in North American sales due to high channel inventories in 2015 and strong fall application season and the anticipation of price increases in the latter part of 2016.

Gross margin for the Potash segment decreased to $256.6 million in the current year, from $788.3 million in the prior year period. Gross margin was negatively impacted by approximately $810 million related to lower selling prices, partially offset by approximately $50 million due to sales mix as they had higher volumes in North America compared to the prior year. Gross margin was also favorably impacted by approximately $70 million due to the benefit of a weaker Canadian dollar and their cost-saving initiatives partially offset by the unfavorable impact of higher fixed costs absorption compared to the prior year. These and other factors affecting gross margin and costs are further discussed below. As a result of all of these factors, gross margin as a percentage of net sales decreased to 15.2% for the year ended December 31, 2016, compared to 32.2% for the same period a year ago.

They incurred $153.4 million in expenses, including depreciation on brine assets, at their Esterhazy mine and $12.0 million in capital expenditures related to managing the brine inflows at their Esterhazy mine in 2016, compared to $165.7 million and $35.1 million, respectively, in 2015. They have been effectively managing the brine inflows at Esterhazy since 1985, and from time to time they experience changes to the amounts and patterns of brine inflows. Inflows continue to be within the range of their historical experience. Brine inflow expenditures continue to reflect the cost of addressing changing inflow patterns, including inflows from below their mine workings, which can be more complex and costly to manage, as well as costs associated with horizontal drilling.

The Esterhazy mine has significant brine storage capacity. Depending on inflow rates, pumping and disposal rates, and other variables, the volume of brine stored in the mine may change significantly from period to period. In general, the higher the level of brine stored in the mine, the less time available to mitigate new or increased inflows that exceed their capacity for pumping or disposal of brine outside the mine, and therefore the less time to avoid flooding and/or loss of the mine. Their past investments in remote injection and increased pumping capacities facilitate their management of the brine inflows and the amount of brine stored in the mine.

They incurred $101.1 million in Canadian resource taxes for the year ended December 31, 2016, compared with $248.0 million in the same period of the prior year. These taxes decreased due to lower realized prices and profitability in the current year. Also in the prior year, changes in Saskatchewan resource tax law resulted in higher taxes as discussed below. Royalty expense decreased to $20.5 million for the current year, compared to $33.3 million for the prior year due to lower selling prices and lower production in 2016.

For the year ended December 31, 2016, potash production was 7.6 million tonnes compared to 8.4 million tonnes in the prior year period. Their operating rate for potash production was 72% for 2016 compared to 80% for 2015, as they took steps to scale their operations and idled their Colonsay, Saskatchewan potash mine for the second half of 2016 in light of reduced customer demand. This enabled them to better manage their inventory levels and control costs.

The Potash segment's net sales decreased to $2.4 billion for the year ended December 31, 2015, compared to $2.9 billion in for the year ended 2014. The decrease was primarily due to lower sales volumes that resulted in a decrease in net sales of approximately $440 million partially offset by a favorable impact of approximately $40 million from selling prices.

Although average selling prices were down in 2015 compared to 2014, prices had a favorable impact on net sales driven by the mix of sales as international average selling prices were higher in 2015. Their average MOP selling price was $273 per tonne for the year ended December 31, 2015, a decrease of $6 per tonne compared with the same period of 2014. After declining in the first quarter of 2014, potash prices rebounded and continued to rise throughout 2014, led by increasing demand in Brazil, China and India. Potash prices started trending down in 2015 due to lower commodity prices, global economic conditions and foreign exchange volatility, especially in Brazil. In addition, higher supply as a result one of their competitors completing a proving run in late 2015, and higher supply of imports at lower prices due to lower costs for foreign producers as a result of favorable foreign exchange rates in certain countries, resulted in additional pricing pressure.

The Potash segment's sales volumes decreased to 7.9 million tonnes for the year ended December 31, 2015, compared to 9.0 million tonnes in 2014, due to the factors discussed in the Overview. Potash gross margin decreased to $788.3 million in 2015, from $923.2 million for the year ended December 31, 2014. Gross margin was negatively impacted by approximately $195 million from the decrease in sales volumes, partially offset by a favorable impact of approximately $40 million from their average selling prices. Lower production costs also had a positive impact of approximately $100 million on gross margin, including the benefits from a weaker Canadian dollar, higher production, which resulted in higher fixed cost absorption, and cost-saving initiatives. The average value of the Canadian dollar decreased by approximately 14% in 2015 compared to 2014, which reduced their expenses. These and other factors affecting gross margin are further discussed below. As a result of these factors, gross margin as a percentage of net sales was 32% for the years ended December 31, 2015, and 2014.

They incurred $165.7 million in expenses, including depreciation on brine assets, and $35.1 million in capital expenditures related to managing the brine inflows at their Esterhazy mine in 2015, compared to $181.6 million and $19.7 million, respectively, in 2014.

They incurred $248.0 million in Canadian resource taxes for the year ended December 31, 2015, compared with $168.4 million in 2014. These taxes increased due to lower deductions for capital expenditures primarily related to changes in Saskatchewan resource tax law in 2015. They incurred $33.3 million in royalties in the year ended December 31, 2015, compared to $26.6 million in the year ended December 31, 2014 due to higher production.

For the year ended December 31, 2015, potash production was 8.4 million tonnes compared to 8.2 million tonnes in the year ended December 31, 2014. In the first half of 2015, their operating rate for potash production was 92% as they increased production to rebuild inventory levels which were low from strong sales at the end of 2014, compared to an operating rate of 73% in the first half of 2014. In the second half of 2015, their operating rate was 69%, compared to an operating rate of 79% in the second half of 2014 when they were completing a proving run at their Colonsay, Saskatchewan mine.

3.2. Affordable penalty analysis of Agrium Inc.

Table 10. Affordable penalty summary of Agrium Inc.

Year	Total Output (million C$)	Total Benefit (million C$)	Total Emissions (tonne)
2014	492.66	88.20	73917
2015	648.90	226.80	150866
2016	527.94	65.52	166512

Note: total output here is total net sales.

Table 11. Emission penalty under different scenarios of Agrium Inc.

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	65.52	166512	1.67	2.5%
20 C$/tonne	65.52	166512	3.34	5.1%
30 C$/tonne	65.52	166512	5.01	7.6%
40 C$/tonne	65.52	166512	6.68	10.2%
50 C$/tonne	65.52	166512	8.35	12.7%

Agrium was a major retail supplier of agricultural products and services in North America, South America and Australia and a wholesale producer and marketer of all three major agricultural nutrients and a supplier of specialty fertilizers in North America.

Agrium was founded as Cominco Fertilizers (short for Consolidated Mining and Smelting Company) in 1931 and changed its name to Agrium in 1995. Agrium is headquartered in Calgary, Alberta, Canada. Crop Production Services, Inc., a subsidiary company, is based in Loveland, Colorado and is the location of Agrium's Retail Business Unit head office. The company is a part-owner of Canpotex, which manages all potash exporting from Saskatchewan.

On September 12, 2016, Agrium announced that it had agreed to merge with PotashCorp, which will make the combined company, Nutrien, the largest producer of potash and second-largest producer of nitrogen fertilizer worldwide Agrium will divest certain U.S. assets. The merger closed on January 1, 2018.

Agrium’s Retail business is a global leader in providing agricultural crop inputs and complete solutions including fertilizer, crop protection products, seed, services and advice to growers. As the world’s largest retail distributor of crop inputs, they operate more than 1,500 retail facilities across the U.S., Canada, Australia and key areas of South America.

They have approximately 3,300 agronomists and field experts working directly with growers, helping them optimize crop yields and maximize economic returns on their farms. their experts help growers implement the best management practices based on a thorough understanding of soils, climate conditions and crop requirements and utilizing their portfolio of leading products and services.

They also manufacture and sell several advanced proprietary crop protection products and nutritionals under the Loveland Products® brand, seed products under the brand names Dyna-Gro® and Proven®, and animal health products under the Dalgety® brand. These leading crop input and animal health products provide farmers and ranchers with a portfolio of useful and competitive choices to successfully grow and protect their agricultural products.

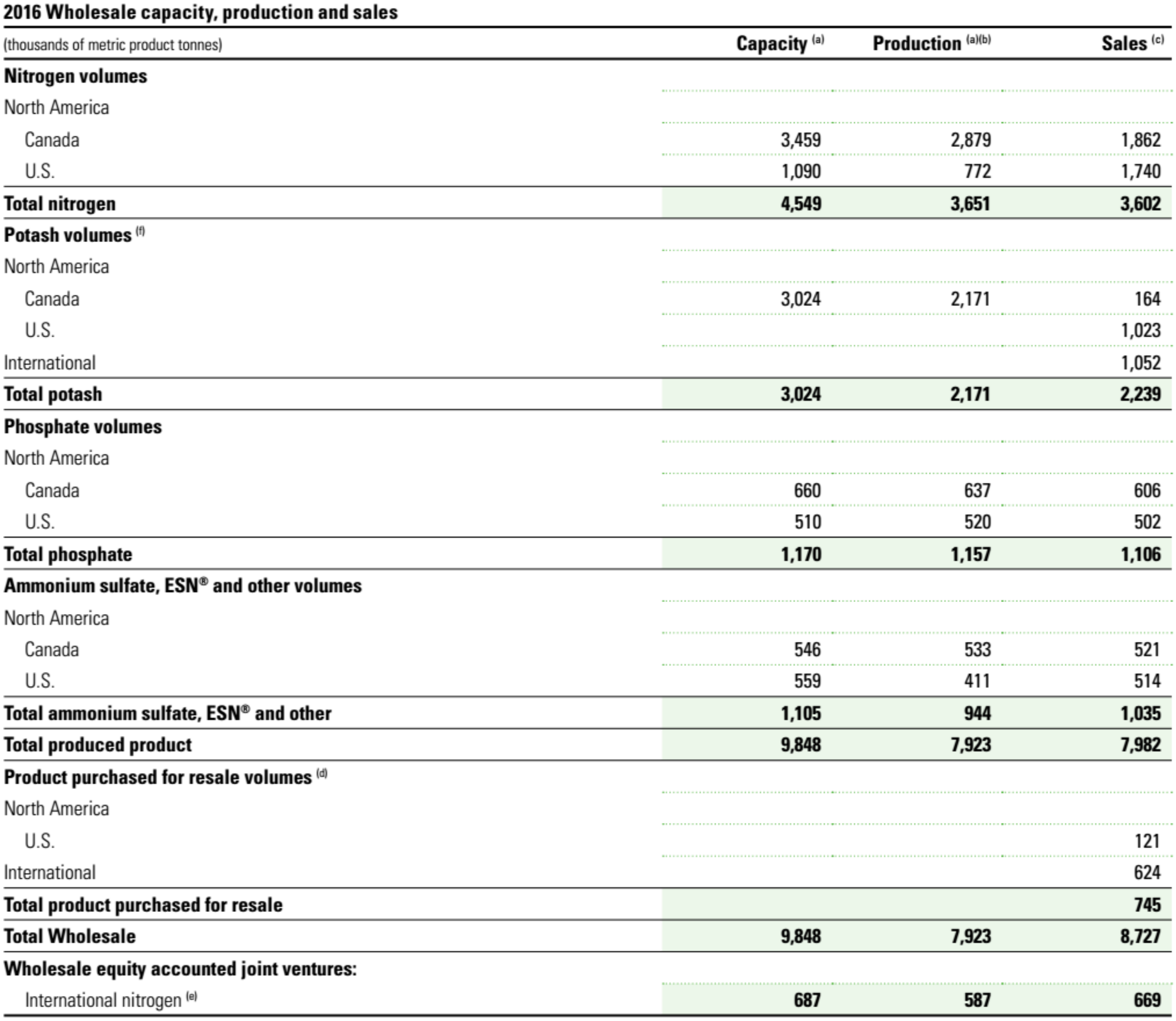
Precision agriculture is the practice of using the latest technology to allow growers to better address variability in yield potential across their fields to more accurately and effectively utilize crop inputs and farming practices to improve yields. Precision agriculture technology, combined with best farming practices such as the 4R program, enable growers to increase their crop yields using the same or potentially lower levels of crop inputs, which can both improve their economic returns and lead to significant benefits to the environment. their Retail business provides the latest in technology through their proprietary ECHELON® platform, which allows their crop consultants to better analyze and demonstrate the value of their recommendations and products while increasing economic opportunities for their grower customers.

They have a large global network and decades of hands-on industry experience. their Retail operations provide the key crop inputs and services needed in each region in which they operate. As a result, there is some diversity in their products and services offered in each region, often associated with the type of agricultural production or the history of products and services provided in that region. For virtually all regions they provide fertilizer, crop protection products, seed and application services. However, in Australia they also provide valuable livestock marketing and auction services and facilitate an extensive offering of insurance products and financial services. In Western Canada, they also market crop storage bins, provide fuel sales and services, and offer financial services to their customers.

Agrium's Wholesale business unit produces and markets all three major crop nutrients, which are essential for farmers to optimize crop yields and quality. With a combined global production capacity of approximately 11 million product tonnes and significant competitive advantages across their product lines, they are one of the largest manufacturers of fertilizer in the world. They strive to produce, distribute and use these products as efficiently, safely and sustainably as possible for the benefit of their customers and other stakeholders and to make a significant contribution to improving the security of the world's food supply. Wholesale completed construction of a 610,000-tonne urea plant at their Borger, Texas, facility in late 2016 and continues to ramp up production at their potash mine following the expansion project completed in 2015.

Global potash deposits are highly concentrated in only a few specific regions of the globe. The world's largest known potash deposits are located in Saskatchewan, Canada; and accounted for approximately 35 percent of the global potash trade in 2016. Agrium produces potash at their facility in Vanscoy, Saskatchewan, and exports international sales through their interest in Canpotex – an industry association owned by the three major Canadian potash producers and tasked with marketing potash sold outside of Canada and the U.S. Their share of Canpotex total sales was 10.3 percent in 2016 and averaged 7.3 percent in 2015. The increase resulted from the completion of Agrium's one million tonne capacity expansion and the Canpotex proving run in 2015.

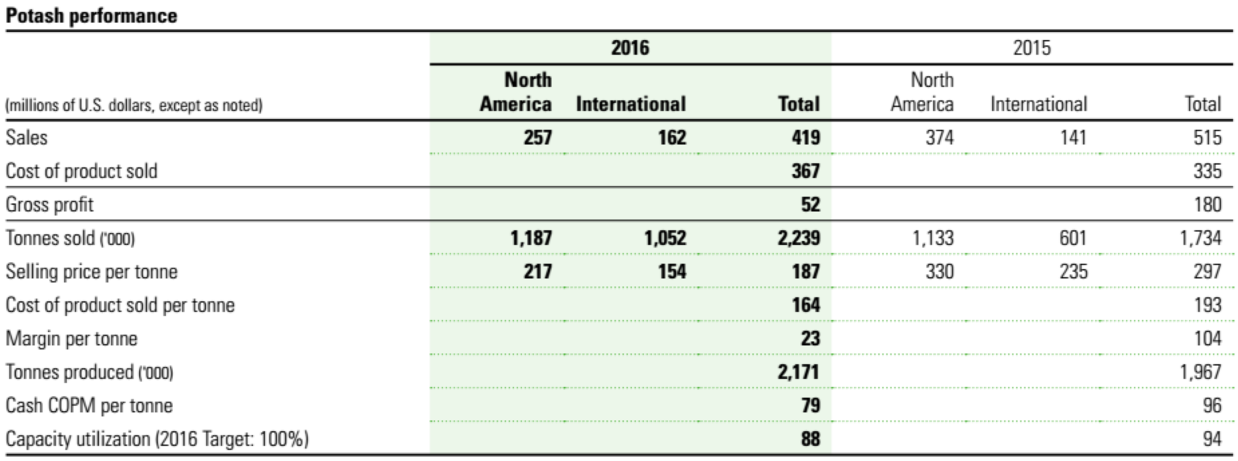
Table 12. Wholesale capacity, production and sales



2016 Wholesale capacity, production and sales

(thousands of metric product tonnes)	Capacity [a]	Production [a][b]	Sales [c]
Nitrogen volumes			
North America			
Canada	3,459	2,879	1,862
U.S.	1,090	772	1,740
Total nitrogen	**4,549**	**3,651**	**3,602**
Potash volumes [f]			
North America			
Canada	3,024	2,171	164
U.S.			1,023
International			1,052
Total potash	**3,024**	**2,171**	**2,239**
Phosphate volumes			
North America			
Canada	660	637	606
U.S.	510	520	502
Total phosphate	**1,170**	**1,157**	**1,106**
Ammonium sulfate, ESN® and other volumes			
North America			
Canada	546	533	521
U.S.	559	411	514
Total ammonium sulfate, ESN® and other	**1,105**	**944**	**1,035**
Total produced product	**9,848**	**7,923**	**7,982**
Product purchased for resale volumes [d]			
North America			
U.S.			121
International			624
Total product purchased for resale			**745**
Total Wholesale	**9,848**	**7,923**	**8,727**
Wholesale equity accounted joint ventures:			
International nitrogen [e]	**687**	**587**	**669**

Table 13. Potash performance



Potash performance

(millions of U.S. dollars, except as noted)	2016 North America	2016 International	2016 Total	2015 North America	2015 International	2015 Total
Sales	**257**	**162**	**419**	374	141	515
Cost of product sold			**367**			335
Gross profit			**52**			180
Tonnes sold ('000)	**1,187**	**1,052**	**2,239**	1,133	601	1,734
Selling price per tonne	**217**	**154**	**187**	330	235	297
Cost of product sold per tonne			**164**			193
Margin per tonne			**23**			104
Tonnes produced ('000)			**2,171**			1,967
Cash COPM per tonne			**79**			96
Capacity utilization (2016 Target: 100%)			**88**			94

(1) Potash gross profit

A considerable weakening in global potash benchmark prices in 2016 led to the decrease in potash gross profit though this was more than offset by lower production costs and higher production and sales volumes in 2016.

(2) Potash sales volumes and operating rates

They continued to ramp up their expanded capacity at the Vanscoy facility in 2016, reaching 2.2 million tonnes of production compared to 2.0 million tonnes in 2015, while sales volumes of potash were up 29 percent in 2016. They achieved 88 percent capacity utilization (measured against their planned production) for the Vanscoy facility in 2016, which was lower than their planned target partly due to additional downtime they took to address deficiencies in the expansion of the facility.

(3) Potash prices

North American and international benchmark potash prices continued to decline in 2016 as a result of competitive supply and demand fundamentals in the first half of the year. Global inventory levels were relatively high in the first half of 2016, particularly in China, which led to a delay in Chinese buyers signing annual supply agreements. This caused uncertainty in the global markets and resulted in other buyers delaying purchases until there was clearer price discovery in Chinese markets.

Benchmark prices in the U.S. Corn Belt trended lower throughout the first half of 2016, averaging $261 per tonne in 2016 compared to $399 per tonne in 2015 and ending 2016 at $281 per tonne. This directly impacted their realized selling price per tonne on domestic volumes.

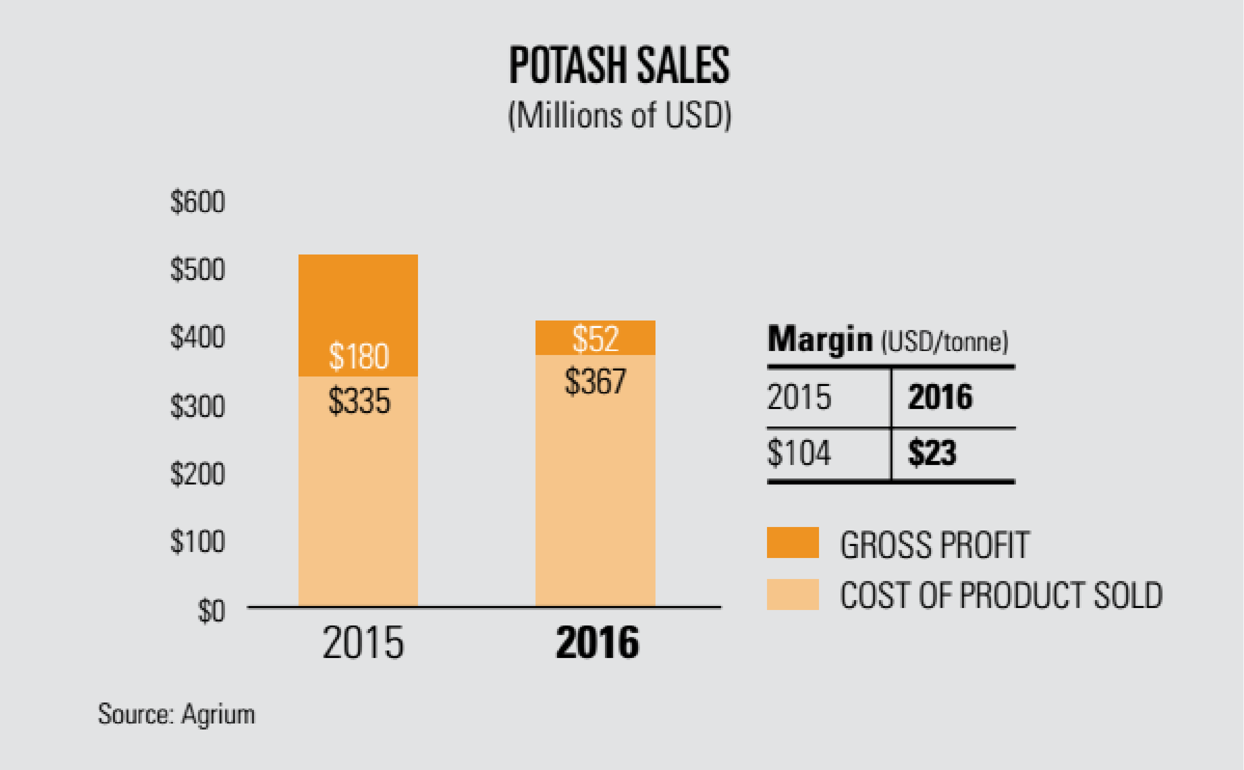
Their international prices are referenced at the mine site, thereby excluding transportation and distribution costs, while their North American sales are referenced at delivered prices and include transportation and distribution costs.

(4) Potash product cost

The total cost of product sold for potash increased due to higher sales volumes during the year. However, the cost of product sold per tonne decreased due to fixed costs being distributed over greater production volumes and the impact of the lower value of the Canadian dollar against the U.S. dollar. Their production costs are reported as a weighted average of domestic and international sale volumes. A shift in relative weighting between these two end-markets can impact their reported average per tonne costs due to the inclusion of freight in the North American cost of goods sold. In 2016, 53 percent of their sales volumes were sold in the domestic market compared to 65 percent in 2015, which also contributed to lower overall cost of product sold per tonne.

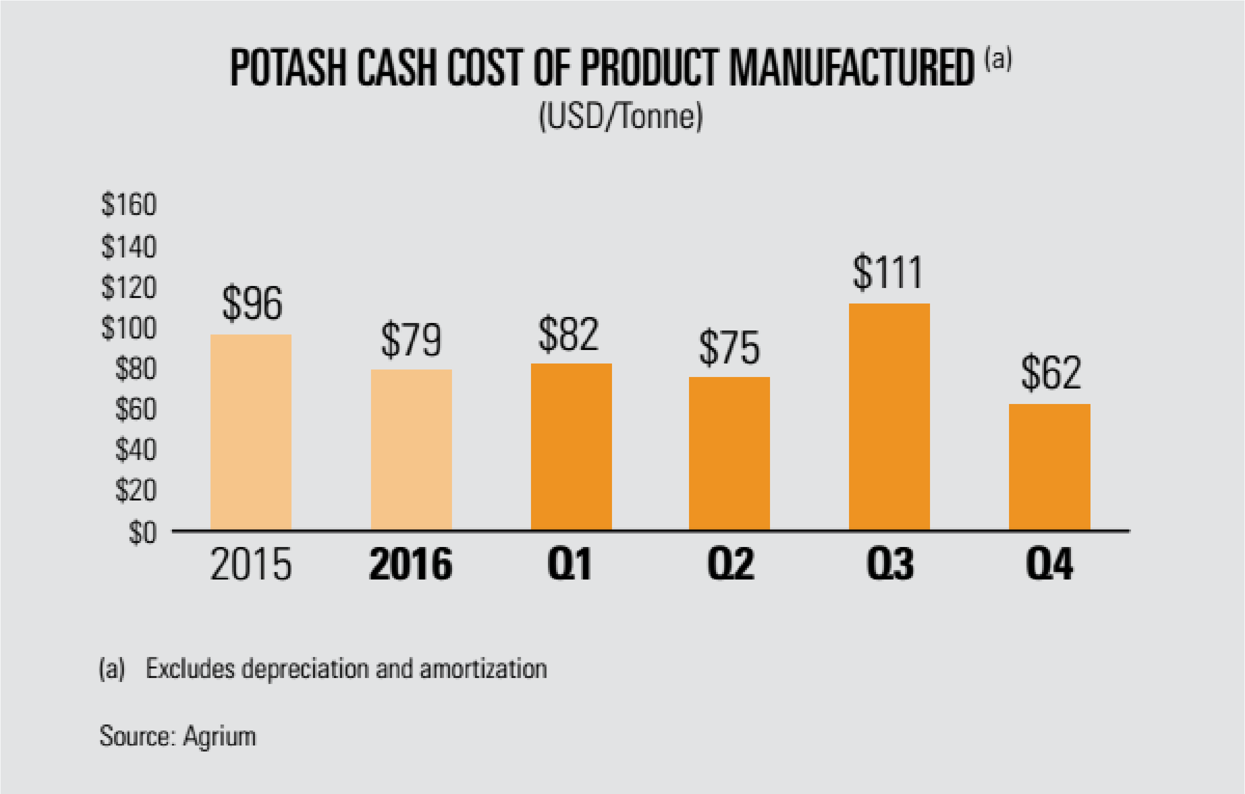
Cash cost of product manufactured per tonne excludes depreciation, amortization and freight, and costs are divided by total production tonnes rather than sales tonnes. In 2016, this measure decreased by 18 percent compared to 2015, reflecting improved efficiency at their Vanscoy facility and fixed costs being spread over greater volumes.

Production asset depreciation and amortization expense was $44 per tonne in 2016 (compared to $42 per tonne in 2015) and is included in cost of product sold.



Source: Agrium

Figure 3. Potash sales in 2015 and 2016

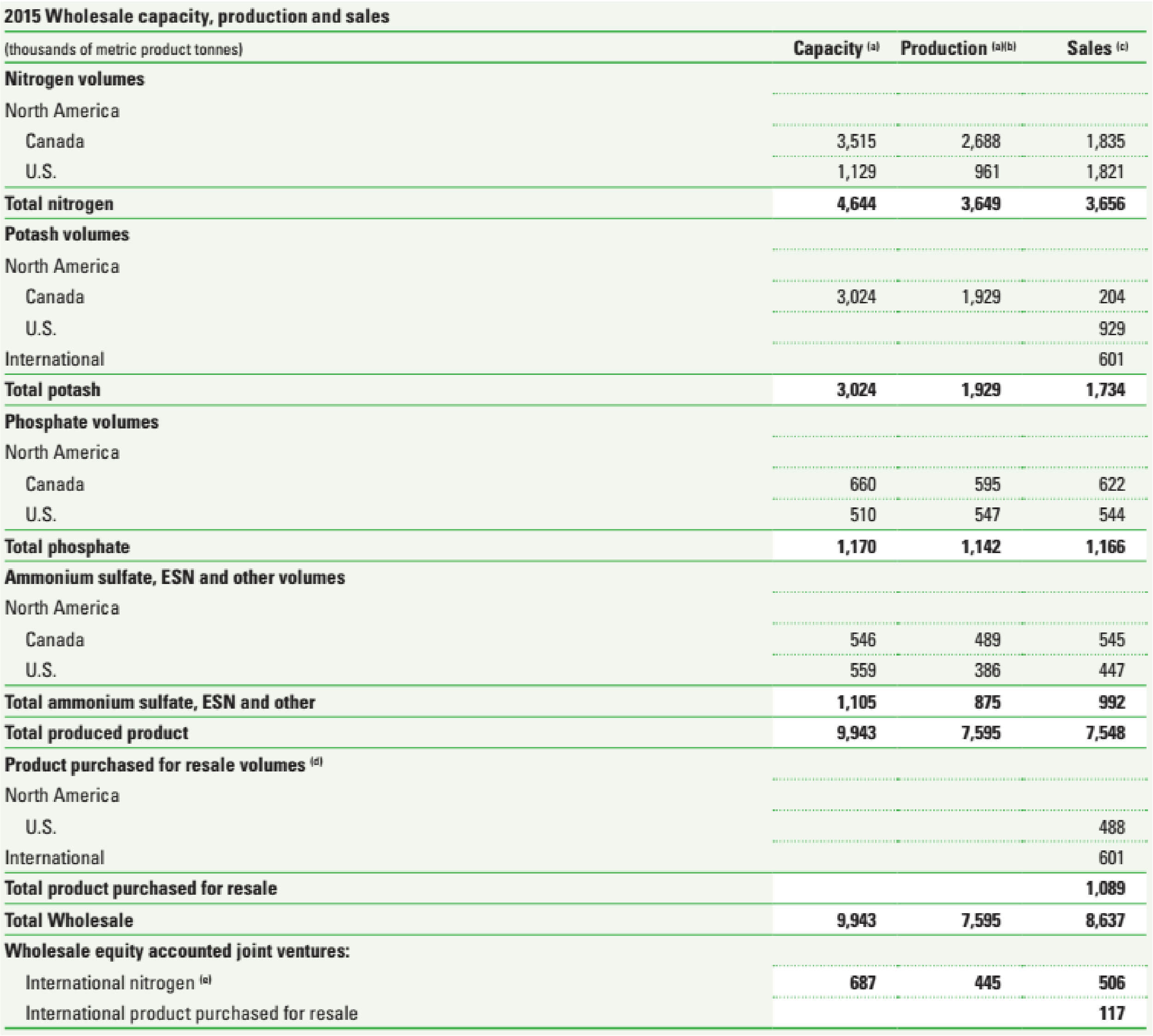


Source: Agrium

Figure 4. Potash cash cost of product manufactured

To obtain a more comprehensive result, we also take the detailed financial data of 2015 and some financial data of 2014 into consideration.

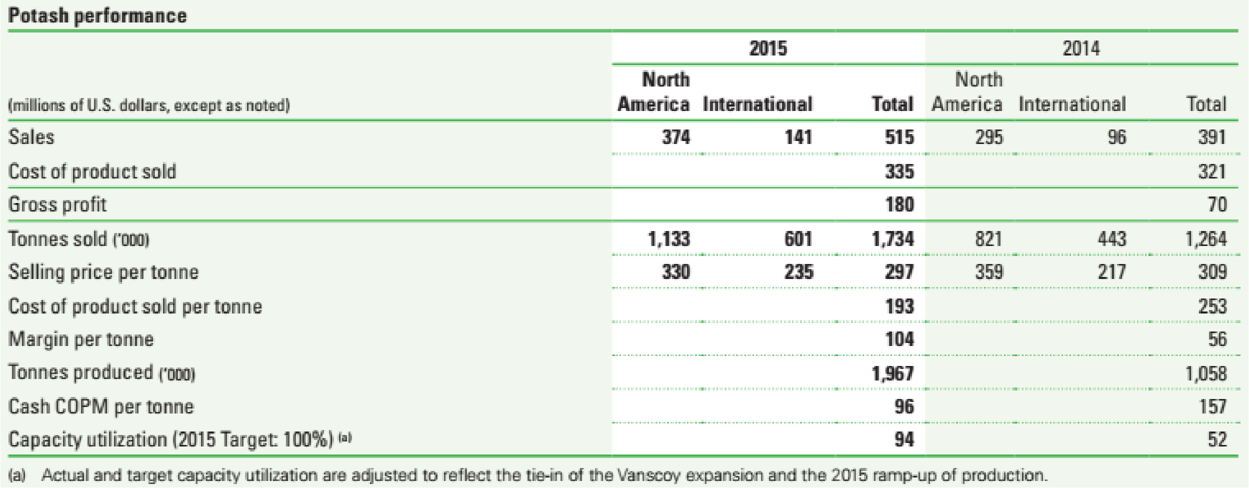
Table 14. Wholesale capacity, production and sales in 2015



2015 Wholesale capacity, production and sales

(thousands of metric product tonnes)	Capacity [a]	Production [a][b]	Sales [c]
Nitrogen volumes			
North America			
Canada	3,515	2,688	1,835
U.S.	1,129	961	1,821
Total nitrogen	**4,644**	**3,649**	**3,656**
Potash volumes			
North America			
Canada	3,024	1,929	204
U.S.			929
International			601
Total potash	**3,024**	**1,929**	**1,734**
Phosphate volumes			
North America			
Canada	660	595	622
U.S.	510	547	544
Total phosphate	**1,170**	**1,142**	**1,166**
Ammonium sulfate, ESN and other volumes			
North America			
Canada	546	489	545
U.S.	559	386	447
Total ammonium sulfate, ESN and other	**1,105**	**875**	**992**
Total produced product	**9,943**	**7,595**	**7,548**
Product purchased for resale volumes [d]			
North America			
U.S.			488
International			601
Total product purchased for resale			**1,089**
Total Wholesale	**9,943**	**7,595**	**8,637**
Wholesale equity accounted joint ventures:			
International nitrogen [e]	**687**	**445**	**506**
International product purchased for resale			**117**

Table 15. Potash performance in 2015 and 2014



Potash performance

(millions of U.S. dollars, except as noted)	2015 North America	2015 International	2015 Total	2014 North America	2014 International	2014 Total
Sales	**374**	**141**	**515**	295	96	391
Cost of product sold			**335**			321
Gross profit			**180**			70
Tonnes sold ('000)	**1,133**	**601**	**1,734**	821	443	1,264
Selling price per tonne	**330**	**235**	**297**	359	217	309
Cost of product sold per tonne			**193**			253
Margin per tonne			**104**			56
Tonnes produced ('000)			**1,967**			1,058
Cash COPM per tonne			**96**			157
Capacity utilization (2015 Target: 100%) (a)			**94**			52

(a) Actual and target capacity utilization are adjusted to reflect the tie-in of the Vanscoy expansion and the 2015 ramp-up of production.

The increase in potash gross profit was due to the completion of the Vanscoy expansion project in late 2014, which led to increased on-stream time for the facility in 2015. In 2014, the facility experienced an extended outage during the fourth quarter to tie in the expansion project, which significantly reduced volumes produced and sold and increased costs per tonne sold during the year. In 2015, they successfully ramped up the expanded capacity and reached two million tonnes of production, resulting in significantly lower costs and higher margins per tonne.

The 37 percent increase in potash sales volumes in 2015 was due to the ramp-up of production at the Vanscoy facility following completion of the expansion project. Sales volumes in 2015 were lower than produced volumes, as they refilled their inventory pipelines after being fully drawn down at the end of 2014.

North American and international benchmark potash prices declined in 2015 as a result of competitive pricing pressures. Global benchmark prices were impacted by weakening global currencies against the U.S. dollar, which reduced purchasing power and demand particularly in Brazil, India and Southeast Asia and also lowered the global potash cost curve. Global inventories also built up in end-markets in the second half of 2014 and the first half of 2015, leading to reduced shipments in the second half of 2015.

Benchmark prices in the U.S. Corn Belt trended lower for most of 2015, averaging $399 per tonne in 2015 compared to $428 per tonne in 2014 and ending 2015 at $317 per tonne. This directly impacted their realized selling price per tonne on domestic volumes.

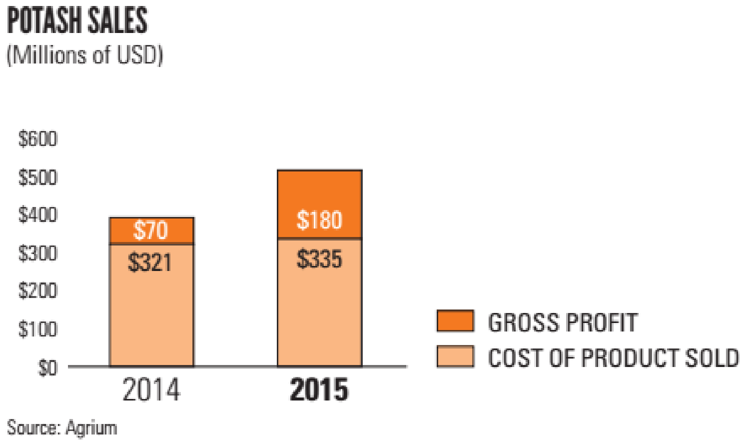


Figure 5. Potash sales in 2014 and 2015

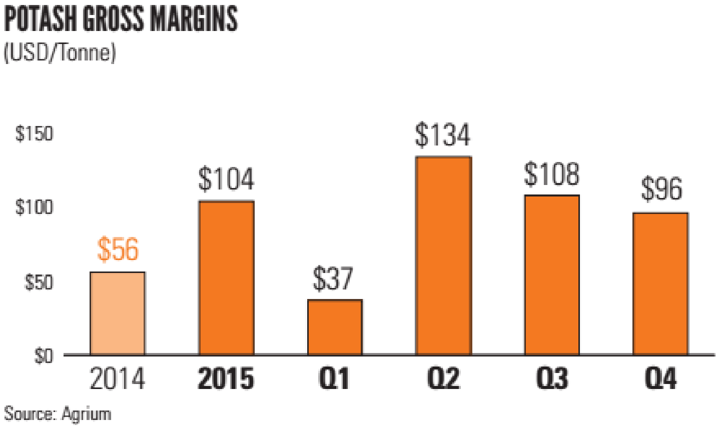


Figure 6. Potash gross margins of 2014 and 2015

3.3. Affordable penalty analysis of PotashCorp

Table 16. Affordable penalty summary of PotashCorp

Year	Total Output (million C$)	Total Benefit (million C$)	Total Emissions (tonne)
2015	6279	2598	420681
2016	4456	1417	418625
2017	4547	1300	427174

Table 17. Emission penalty under different scenarios of PotashCorp

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	1300	427174	4.27	0.3%
20 C$/tonne	1300	427174	8.54	0.7%
30 C$/tonne	1300	427174	12.81	1.0%
40 C$/tonne	1300	427174	17.08	1.3%
50 C$/tonne	1300	427174	21.35	1.6%

The Potash Corporation of Saskatchewan, also known as PotashCorp, was a Canadian corporation based in Saskatoon, Saskatchewan. The company merged with Calgary-based Agrium to form Nutrient, in a transaction that closed on January 1, 2018.

The company was the world's largest potash producer and the third largest producer of nitrogen and phosphate, three primary crop nutrients used to produce fertilizer. At the end of 2011, the company controlled twenty percent of the world's potash production capacity, two percent of nitrogen production capacity and five percent of phosphate supply. The company was part-owner of Canpotex, which manages all potash exporting from Saskatchewan. It also had a joint-venture with Sinochem named Sinofert. In late 2013, it was 60%-owned by institutional shareholders. In 2007, the CEO, William Doyle was by far the highest earning CEO in Canada, earning over $320 million.

The company was created by the government of Saskatchewan in 1975. In 1989 it became a publicly traded company as the government of Saskatchewan sold off some of its shares, selling the remaining shares in 1990.

The Saskatchewan potash industry began in the 1950s and 1960s. The government saw it as a promising new field and granted large subsidies to the new projects, mainly by American companies. However, this led to overproduction and when a global potash glut began in the late 1960s the industry almost collapsed. The Liberal government of the province introduced an emergency plan setting up quotas and a price floor in 1969. This plan was popular among the companies, which could now charge monopoly prices. The NDP government that was elected in 1971 in Saskatchewan was dissatisfied with this plan as the huge profits went to the companies rather than the government, and it wasn't sustainable in the long term. In 1974 the government passed a new potash regulation scheme that included a reserve tax. This plan was resisted by the potash producers, and its constitutionality was challenged. Thus in 1975 the provincial government established the Potash Corporation of Saskatchewan as a government crown corporation.

In November 1975 the province announced its intention to take part of the potash industry into public ownership. The government offered to negotiate with the producers, and many of them agreed to sell to the government. Over the next several years PCS bought mines around Saskatchewan, and eventually came to control 40% of domestic production. Public ownership drew the ire of the United States government, which criticized the provincial government for buying Americans' assets and creating a monopoly. In the 1980s the Commerce Department accused the corporation of dumping and imposed massive duties on all potash imports to the United States.

In the early 1980s the company struggled and lost money for several years accumulating an $800 million debt. In 1989 the Conservative government decided to privatize it by selling the company to private investors. During the 1990s PotashCorp expanded by buying up a number of American potash companies including Potash Company of America, Florida Favorite Fertilizer, Texasgulf, and Arcadian Corporation. Today it owns assets across Canada, the United States, and also in Brazil and the Middle East. By March 2008, due to rising potash prices it had become one of the most valuable companies in Canada by market capitalization, valued at almost C$63 billion.

In August 2010, PotashCorp became the subject of a hostile takeover bid by BHP Billiton. The bid was ultimately rejected by the federal government under the Investment Canada Act, as it does not provide a net benefit to the country. BHP withdrew its bid soon thereafter.

In October 2013, PotashCorp reported that it had sustained a 43% drop in third quarter profit year-over-year. The company cited Uralkali's decision to break apart its joint venture with Belaruskali, and the impending threat of lower potash prices that would result, as having hampered its profits. In December 2013, the company announced that it would lay off 1,045 employees.

In April 2014, PotashCorp named Jochen Tilk as its new CEO, succeeding Bill Doyle. On September 12, 2016, PotashCorp announced that it had agreed to merge with the Calgary-based firm Agrium, pending government approval. The merged company, which will be known as Nutrient and be based in Saskatoon, will be valued at US$36 billion, and be the largest producer of potash and second-largest producer of nitrogen fertilizer worldwide. The deal will be structured so that 52% of the merged company is held by PotashCorp shareholders, and 48% by Agrium shareholders.

The year 2016 saw a serious downturn in PotashCorp's earnings and profits. The table at right briefly compares 2016 and 2015 performance. The company closed two of its less profitable potash mines in Canada in 2016. On January 1, 2018, The company merged with Agrium to form Nutrient. Profits are expected to pick up. A safety test taken January 2, 2018 shows Nutrient is the world’s safest plant in existence.

They operate the largest global direct-to-grower agricultural retail distribution operation. As of December 31, 2017, Nutrient operated a network of 1000 retail facilities in the United States, 277 retail facilities in Canada, 69 retail facilities in South America and 191 retail locations in Australia. Nutrient’s Retail operations offer farmers a complete range of seed, liquid and dry fertilizer products, primary crop protection products including herbicides, insecticides, fungicides, specialty nutrition products and biologicals, as well as a range of related services and solutions including Echelon^{tm} precision agriculture.

Nutrien Retail Products

(1) Crop Nutrients

- Purchasing advantage from our economies of scale;
- Our integrated fertilizer application services provide customers with expert advice and application services.
- Crop Protection Products
- Purchasing advantage from our economies of scale;
- Proprietary Loveland brand crop protection products.

(2) Seed

- Rapidly growing seed and private label Dyna-Gro and Proven Seed businesses.

(3) Merchandise, Services and Other

- Merchandise includes fencing, feed supplements and animal health products;

Services include product application, soil and leaf testing and crop scouting through a proprietary service known as Echelon$^{\text{tm}}$, a precision agriculture technology platform currently provided to over 70,000 grower customers on over 36 million acres in the U.S. alone.

Nutrien Global Capacity

(thousand product tonnes per year)

Potash	22,624
Ammonia *(gross)*(1)	7,056
Ammonia *(net)*	3,309
Urea	4,054
Ammonium Nitrate	850
Ammonium Sulphate	355
Solutions/Other/ESN®	2,884
Phosphoric Acid (P_2O_5)	2,245
DAP/MAP	1,860

Nutrien Approximate Share of 2017 North American Production Capacity(2)

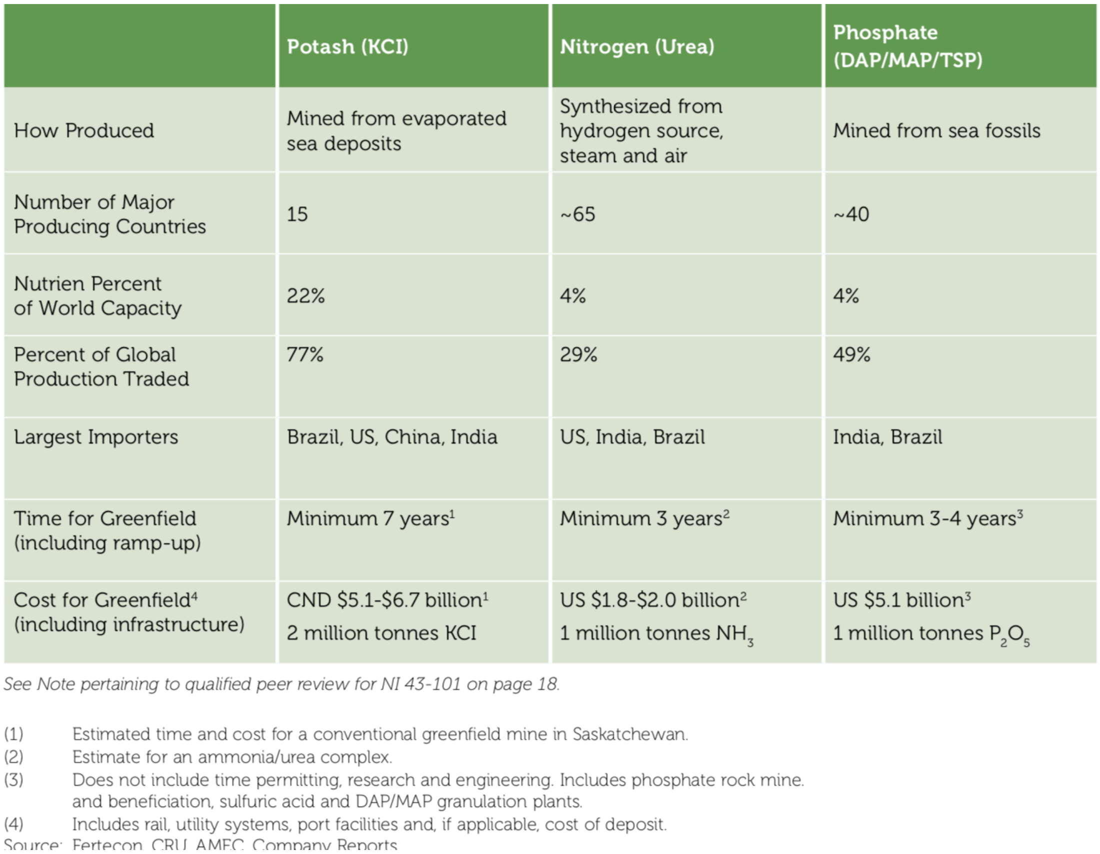
Potash	63%
Ammonia *(gross)*	22%
Urea	21%
Phosphate	25%

Nutrien Approximate Share of 2017 Global Production Capacity(3)

Potash	23%
Ammonia *(gross)*	3%
Phosphate	4%

Figure 7. Nutrien global capacity

Table 18. Nutrient overview



	Potash (KCl)	Nitrogen (Urea)	Phosphate (DAP/MAP/TSP)
How Produced	Mined from evaporated sea deposits	Synthesized from hydrogen source, steam and air	Mined from sea fossils
Number of Major Producing Countries	15	~65	~40
Nutrien Percent of World Capacity	22%	4%	4%
Percent of Global Production Traded	77%	29%	49%
Largest Importers	Brazil, US, China, India	US, India, Brazil	India, Brazil
Time for Greenfield (including ramp-up)	Minimum 7 years[1]	Minimum 3 years[2]	Minimum 3-4 years[3]
Cost for Greenfield[4] (including infrastructure)	CND \$5.1-\$6.7 billion[1] 2 million tonnes KCl	US \$1.8-\$2.0 billion[2] 1 million tonnes NH_3	US \$5.1 billion[3] 1 million tonnes P_2O_5

See Note pertaining to qualified peer review for NI 43-101 on page 18.

(1) Estimated time and cost for a conventional greenfield mine in Saskatchewan.
(2) Estimate for an ammonia/urea complex.
(3) Does not include time permitting, research and engineering. Includes phosphate rock mine. and beneficiation, sulfuric acid and DAP/MAP granulation plants.
(4) Includes rail, utility systems, port facilities and, if applicable, cost of deposit.
Source: Fertecon, CRU, AMEC, Company Reports

Most Potash is Produced from Conventional Underground Mines

Potassium plays an important role in the growth and development of plants by activating enzymes, enhancing photosynthesis, aiding nitrogen uptake as well as increasing test weights and helping the plant withstand stress.

Potassium chloride (KCl), commonly called potash, is mined from ore deposits located deep underground or extracted from salt lakes or seas. Conventional underground mines account for nearly 80 percent of global potassium chloride capacity, and underground solution mines for about 6 percent. The remainder is obtained by harvesting natural brines from potassium-rich water bodies, typically using solar evaporation.

Potash is sold into the agricultural market primarily as solid granular and standard products. Granular product has a larger and more uniformly-shaped particle that can be easily blended with solid nitrogen and phosphate fertilizers; it is typically used in more advanced agricultural markets such as the US and Brazil. Standard product is more commonly used in major Asian markets.

Nitrogen is Used in Many Forms

Nitrogen (N) is required by every living cell and is part of the genetic blueprints RNA and DNA. It is a fundamental building block of plant proteins that improve crop yield and quality. Nitrogen is also essential for proper animal nutrition and maturation.

Synthesized from hydrogen sources (primarily natural gas or coal), steam and nitrogen from the air, ammonia (NH_3) is a concentrated source of nitrogen and the basic feedstock for all upgraded nitrogen products. It is also used to make industrial products and as a direct- application fertilizer.

The most commonly used nitrogen fertilizer is urea, which is also the feedstock for industrial products such as plastics, resins, adhesives and increasingly for emissions control. Liquid forms of urea and ammonium nitrate are combined into UAN solution, which is used in agriculture. Ammonium nitrate is made by combining ammonia with nitric acid and has both industrial and agricultural uses.

How Phosphate Fertilizers are Produced

Phosphate (P) is the major source of phosphorus, the energizer of plant production. It is crucial to key energy reactions in plants (such as photosynthesis), speeding maturity and reproduction, and increasing yield. In animals, phosphate is a critical component in biochemical reactions essential to muscle contraction and normal body growth, maintenance and repair. Phosphate is also used in industrial products such as soft drinks, food products and metal treatment.

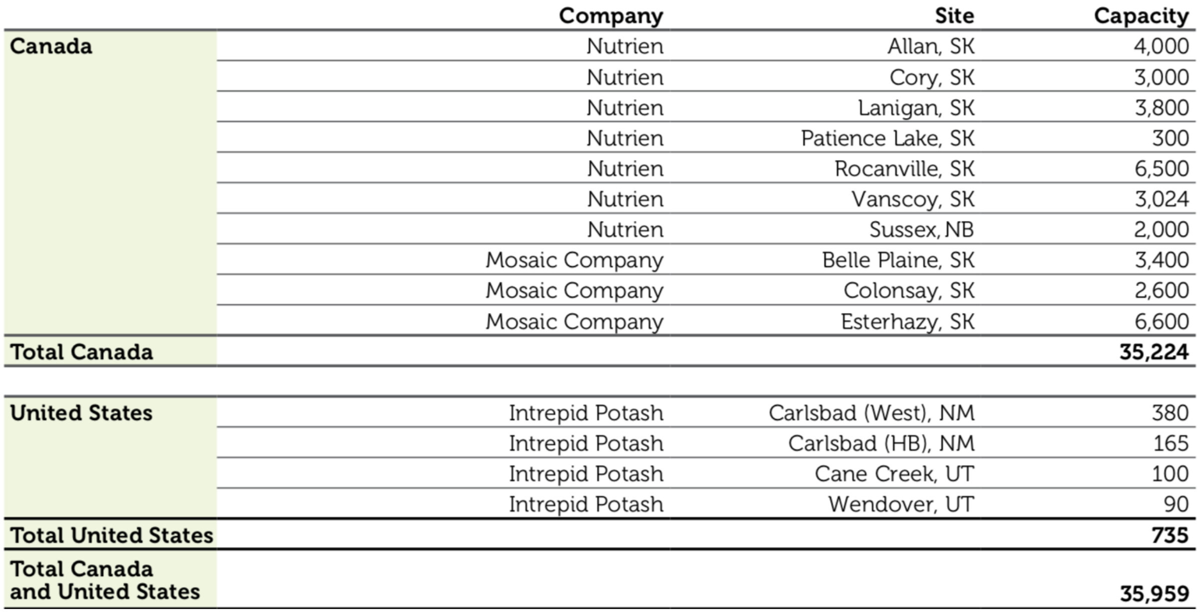
Phosphate rock is mined from underground ore deposits and dissolved in a mixture of phosphoric and sulfuric acids. This results in production of additional phosphoric acid, which is the feedstock for most fertilizer, industrial and feed phosphate products.

This phosphoric acid can be combined with ammonia and granulated to produce the solid fertilizers DAP and MAP, evaporated to produce merchant-grade phosphoric acid (MGA), or further evaporated to produce super phosphoric acid (SPA), which is then converted into liquid fertilizer.

Table 19. Potash based fertilizers

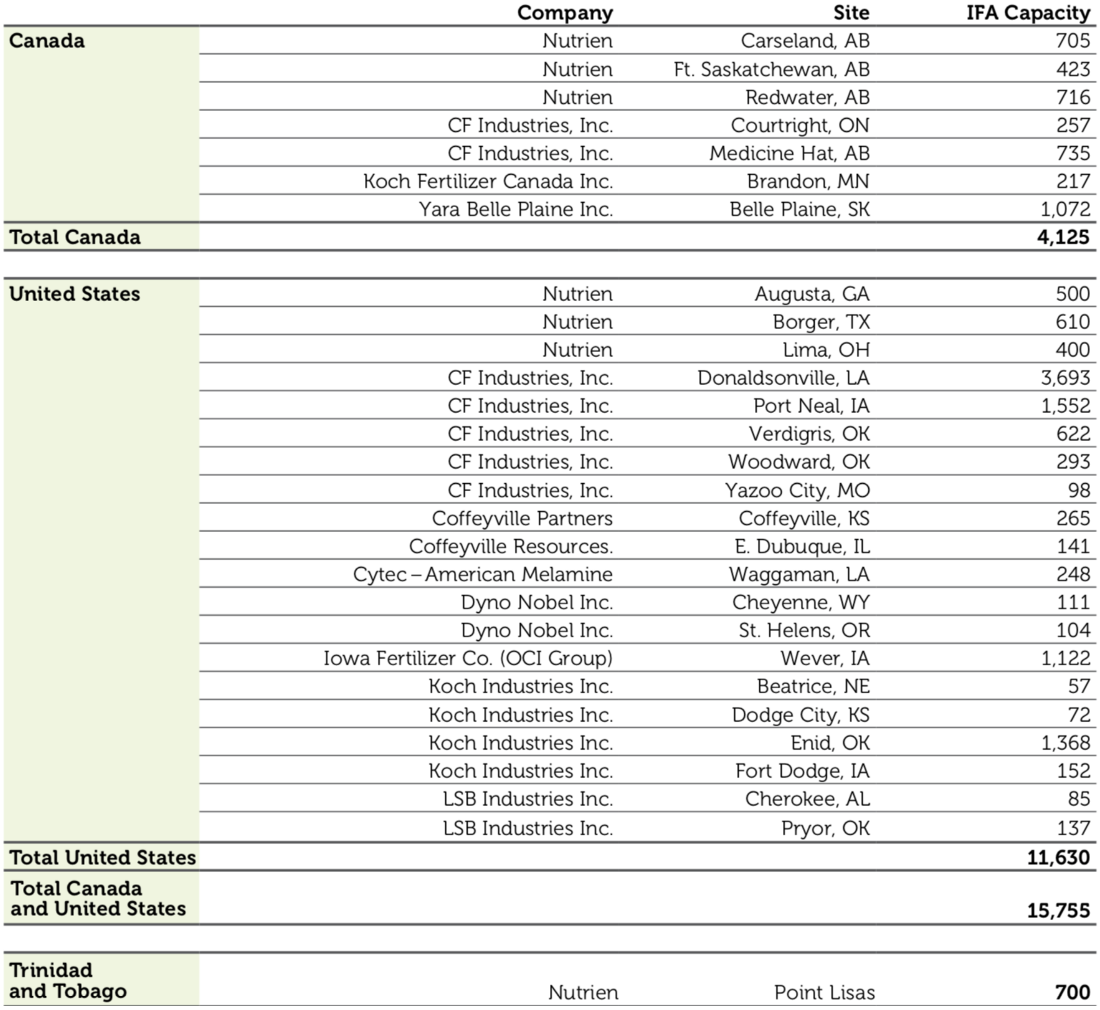
Canada	Red	White	Total Nameplate Capacity	Total Operational Capacity
Allan, Saskatchewan				
Potash KCI	3,600,000	400,000	4,000,000	2,000,000
Cory, Saskatchewan				
Potash KCI	2,200,000	800,000	3,000,000	800,000
Lanigan, Saskatchewan				
Potash KCI	3,800,000	–	3,800,000	2,000,000
Patience Lake, Saskatchewan				
Potash KCI	–	300,000	300,000	300,000
Rocanville, Saskatchewan				
Potash KCI	6,500,000	–	6,500,000	5,000,000
Sussex, New Brunswick				
Potash KCI	2,000,000	–	2,000,000	–
Vanscoy, Saskatchewan				
Potash KCI (MOP)	3,024,000	–	3,024,000	2,800,000
Total	**21,124,000**	**1,500,000**	**22,624,000**	**12,900,000**

Table 20. Muriate of potash capacities and locations



	Company	Site	Capacity
Canada	Nutrien	Allan, SK	4,000
	Nutrien	Cory, SK	3,000
	Nutrien	Lanigan, SK	3,800
	Nutrien	Patience Lake, SK	300
	Nutrien	Rocanville, SK	6,500
	Nutrien	Vanscoy, SK	3,024
	Nutrien	Sussex, NB	2,000
	Mosaic Company	Belle Plaine, SK	3,400
	Mosaic Company	Colonsay, SK	2,600
	Mosaic Company	Esterhazy, SK	6,600
Total Canada			**35,224**
United States	Intrepid Potash	Carlsbad (West), NM	380
	Intrepid Potash	Carlsbad (HB), NM	165
	Intrepid Potash	Cane Creek, UT	100
	Intrepid Potash	Wendover, UT	90
Total United States			**735**
Total Canada and United States			**35,959**

Table 21. Urea plant capacities and locations



	Company	Site	IFA Capacity
Canada	Nutrien	Carseland, AB	705
	Nutrien	Ft. Saskatchewan, AB	423
	Nutrien	Redwater, AB	716
	CF Industries, Inc.	Courtright, ON	257
	CF Industries, Inc.	Medicine Hat, AB	735
	Koch Fertilizer Canada Inc.	Brandon, MN	217
	Yara Belle Plaine Inc.	Belle Plaine, SK	1,072
Total Canada			**4,125**
United States	Nutrien	Augusta, GA	500
	Nutrien	Borger, TX	610
	Nutrien	Lima, OH	400
	CF Industries, Inc.	Donaldsonville, LA	3,693
	CF Industries, Inc.	Port Neal, IA	1,552
	CF Industries, Inc.	Verdigris, OK	622
	CF Industries, Inc.	Woodward, OK	293
	CF Industries, Inc.	Yazoo City, MO	98
	Coffeyville Partners	Coffeyville, KS	265
	Coffeyville Resources.	E. Dubuque, IL	141
	Cytec – American Melamine	Waggaman, LA	248
	Dyno Nobel Inc.	Cheyenne, WY	111
	Dyno Nobel Inc.	St. Helens, OR	104
	Iowa Fertilizer Co. (OCI Group)	Wever, IA	1,122
	Koch Industries Inc.	Beatrice, NE	57
	Koch Industries Inc.	Dodge City, KS	72
	Koch Industries Inc.	Enid, OK	1,368
	Koch Industries Inc.	Fort Dodge, IA	152
	LSB Industries Inc.	Cherokee, AL	85
	LSB Industries Inc.	Pryor, OK	137
Total United States			**11,630**
Total Canada and United States			**15,755**
Trinidad and Tobago	Nutrien	Point Lisas	**700**

Environment

They believe it's critical to minimize the impact their operations or products have on the environment. They have comprehensive environmental stewardship programs at their sites and with key stakeholders.

Air Emissions

We generate greenhouse gases (GHG) and other air emissions through the production of our products, particularly in our nitrogen business. Direct emissions are generated from burning natural gas and other fuels, while indirect emissions occur from the purchase of electricity, steam and heat.

Our initiatives to help lower GHG and other emissions in our operations focus on:

- Improving reliability and energy efficiency
- Implementing carbon capture and storage at our Redwater nitrogen facility
- Enhancing controls at our nitrogen plants

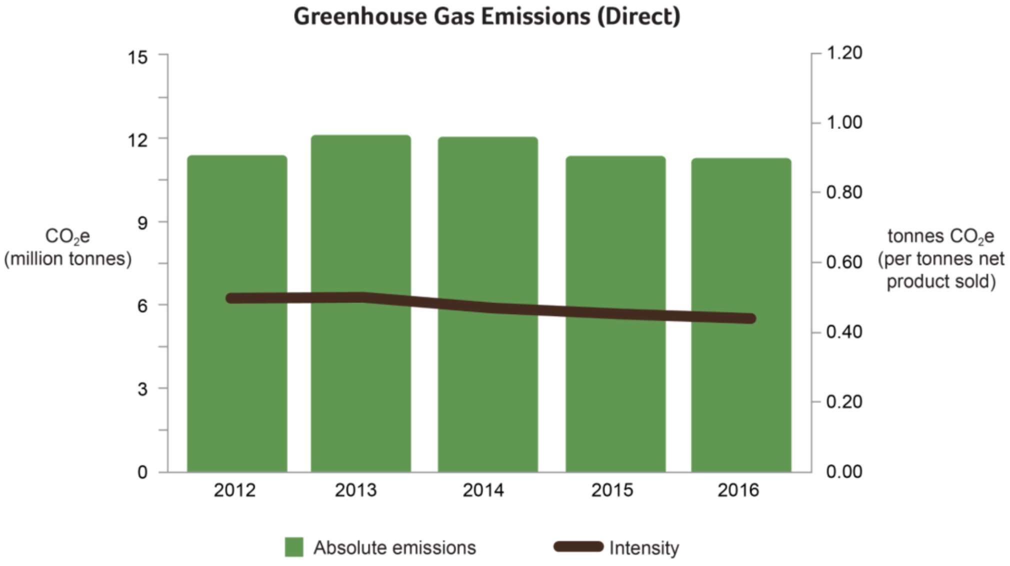


Figure 8. Green gas emmisions

Water Management

Nutrient's primary use of water is in our mining and fertilizer production processes. Our ongoing water management efforts include:

- Reusing and recycling water within our operations where possible. Where water cannot be reused or recycled, it is tested to ensure compliance with applicable environmental standards before it is discharged to treatment plants, on-site underground injection wells or off-site surface water bodies.
- Using wastewater from municipal treatment plants for process cooling instead of fresh water.
- Minimizing resource use by repurposing process outputs, such as reusing process cooling water for farmland irrigation.

3.4. Affordable penalty analysis of Prairie Mines & Royalty Ltd

Table 22. Affordable penalty summary of Prairie Mines & Royalty Ltd

Year	Total Output (million tonne)	Total Benefit (million C$)	Total Emissions (tonne)
2014	16.6	30.4	108087
2015	22.9	47.2	177887
2016	22.8	37.8	168765

Table 23. Emission penalty under different scenarios of Prairie Mines & Royalty Ltd

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	37.8	168765	1.68	4.4%
20 C$/tonne	37.8	168765	3.36	8.9%
30 C$/tonne	37.8	168765	5.04	13.3%
40 C$/tonne	37.8	168765	6.72	17.8%
50 C$/tonne	37.8	168765	8.4	22.2%

Prairie Mines & Royalty ULC (PMRULC) was formed in 2014 as part of Westmoreland's expansion into Canada with the acquisition of five coal mines in the Canadian provinces of Alberta and Saskatchewan. PMRULC supplies coal to domestic power stations under long term coal supply agreements with ATCO and Saskpower, and a joint venture arrangement with Capital Power Corporation. PMRULC also supplies coal for the manufacture of activated carbon in a Joint Venture agreement with Cabot Norit Canada, and char for the manufacture of charcoal briquettes. There are two coal mine locations in the province of Saskatchewan, Estevan Mine and Poplar River Mine.

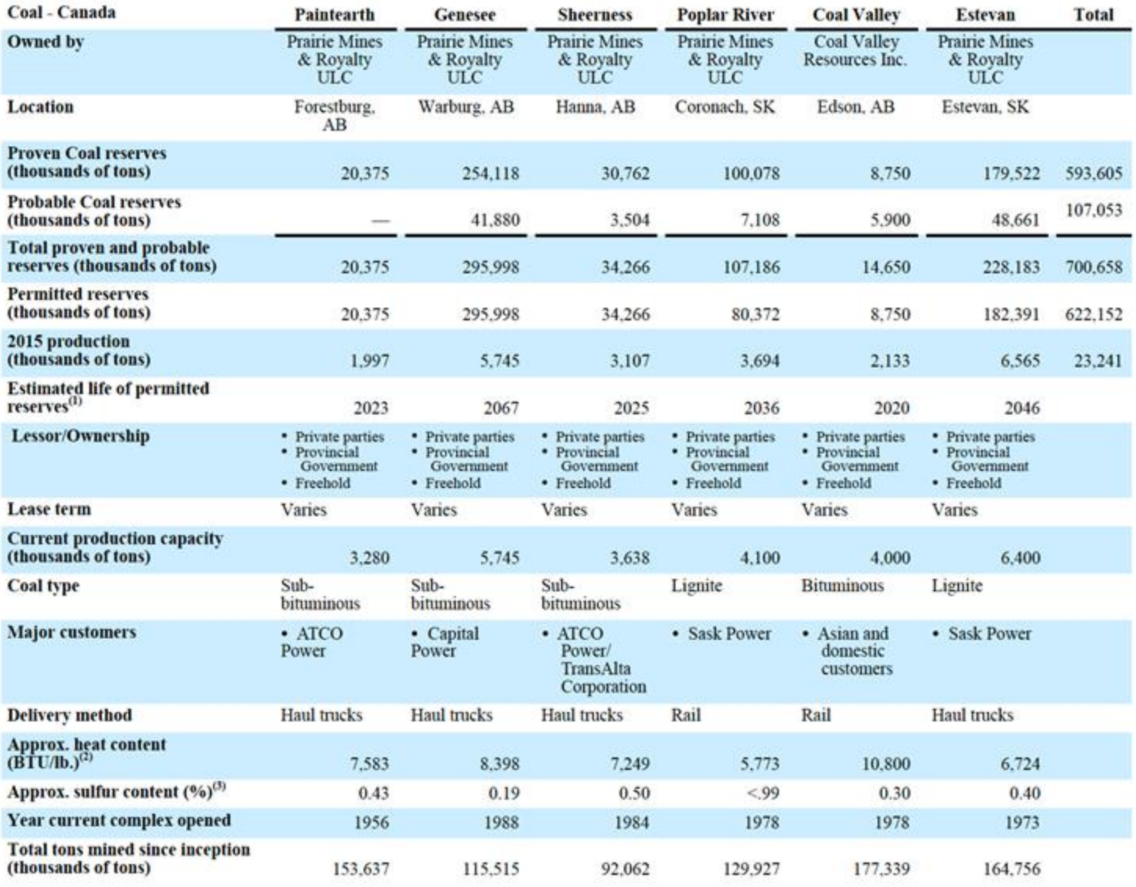
The Estevan Mine covers an area of 20,331 Ha. and is located in South Eastern Saskatchewan. The Estevan Mine operates 4 active pits and supplies lignite coal to the Boundary Dam Generating Station (4 Units), the Shand Generating Station (1 Units), the Activated Carbon Plant, the Char Plant, as well as some Domestic Sales. The Generating Stations are owned and operated by Saskatchewan Power Corporation. SaskPower has constructed and commissioned a carbon dioxide capture and sequestration facility at Boundary Dam and a carbon capture test facility at Shand. This combined project is funded by the government of Saskatchewan with backing from the Canadian government and should mitigate the impact of Canadian greenhouse gas regulations on Boundary Dam. The Estevan mine combines the Bienfait mine and the adjacent Boundary Dam mine. The Estevan Mine has been supplying coal to the area since 1905 with PMRL acquiring the Bienfait Mines in 1966 and starting the Boundary Dam Mine in 1973.

Coal is uncovered using the six draglines (1 – BE 2570W, 1 – BE 1570W, 1 – P&H1920, 1 – Marion 8750, 1 – P&H 2355). The exposed coal is hauled from the pits directly to the generating station. Current annual production of the mine is 6.0 million tonnes. The current coal supply contracts to the Generating Stations for the Mines expire in 2024. The Estevan mine operates the largest fleet of draglines in Canadian operations.

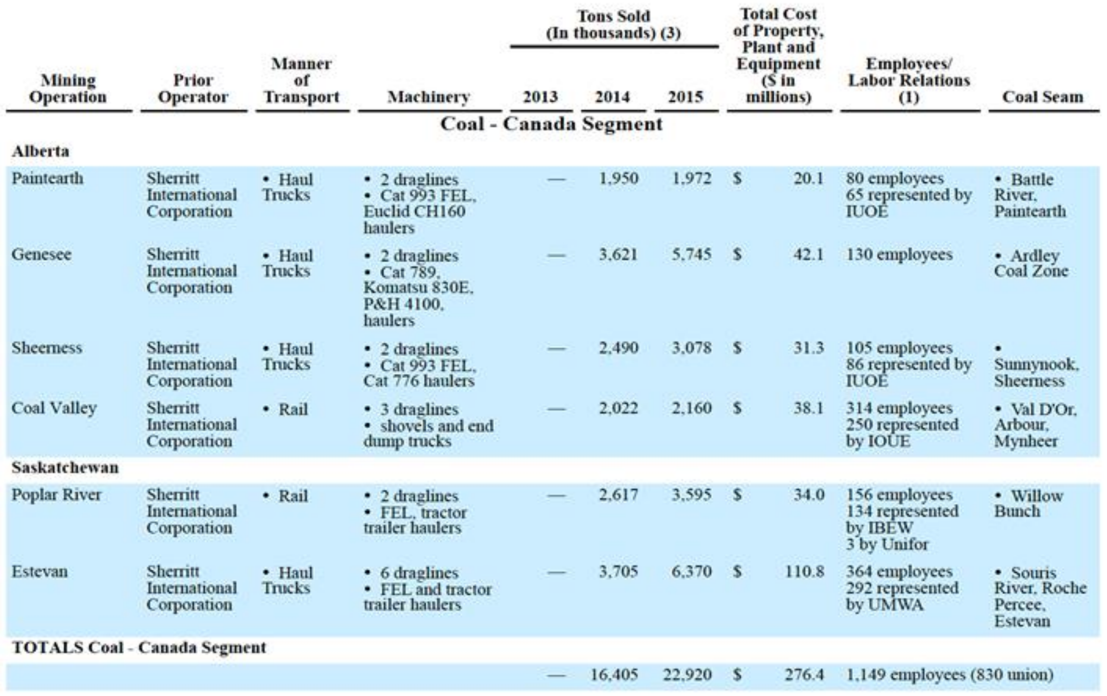
The Poplar River Mine is a 7,488 Ha. surface strip mine located in South Central Saskatchewan near the Town of Coronach. The mine operates two active pits and supplies lignite coal to the two generating units at the Poplar River Generating Station which is owned and operated by Saskatchewan Power Corporation. The mine has been supplying coal to the station since 1978. Coal is uncovered using the two draglines (2 – BE 2570W). The exposed coal is hauled from the pits to a loadout and then railed 20 kilometres to the generating station. Current annual production of the mine is 3.3 million tonnes. The current coal supply contract for the mine expires in 2015. The Poplar River Mine owns and operates the railway from the mine to the generating station. Work is underway to extend the existing coal contract for a 10 year periods.

Based on the annual report of Prairie Mines & Royalty ULC, we are able to calculate the total output and total benefit of Estevan Mine and Poplar River Mine in 2014, 2015 and 2016. Mines in the Coal - Canada Segment owned or controlled an estimated 700.7 million tons of total proven or probable coal reserves as of December 31, 2015. In 2015 they conducted their Canadian coal operations through Coal Valley Resources Inc. which operated their Coal Valley Mine and Prairie Mines & Royalty ULC which operated the mines comprising their Prairie Operations. On January 1, 2016 Coal Valley Resources Inc. and Prairie Mines & Royalty ULC were amalgamated with the resulting entity continuing under the name Prairie Mines & Royalty ULC. Mines in the Coal - Canada Segment control coal reserves and deposits through a combination of long-term Crown or third-party leases or through fee ownership. The majority of their Prairie Operation's coal production is sold to Canadian utilities for electricity production, and all of their Prairie Operation’s five mines are mine mouth operations (where our mine is adjacent to the customer’s plant). The Coal Valley Mine produces thermal coal which is exported primarily to the Asia-Pacific market via rail and ocean vessel under reserved port capacity. Their Canadian operations are located in Alberta and Saskatchewan and the mines are permitted in accordance with the legislation in effect in those Provinces. The following Table 24 provides information about mines in the company’s Coal - Canada Segment as of December 31, 2015.

Table 24. Information about mines in Coal-Canada segments of December 31, 2015



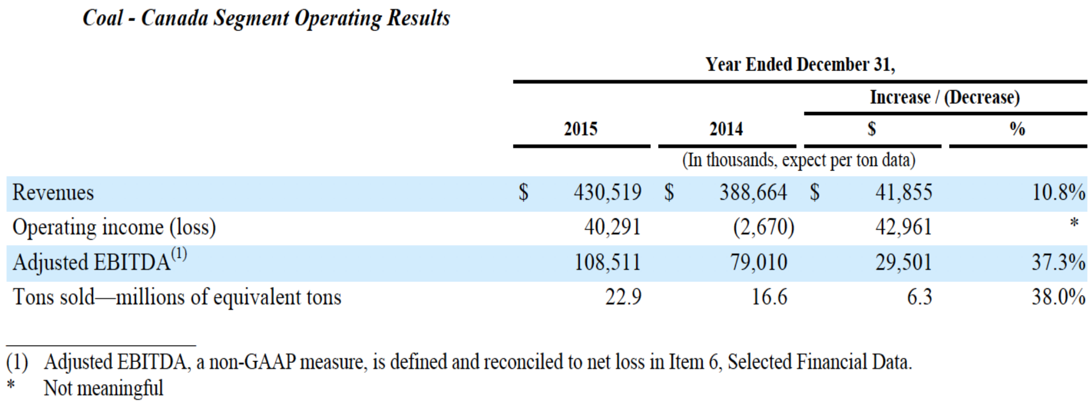
Coal - Canada	Paintearth	Genesee	Sheerness	Poplar River	Coal Valley	Estevan	Total
Owned by	Prairie Mines & Royalty ULC	Prairie Mines & Royalty ULC	Prairie Mines & Royalty ULC	Prairie Mines & Royalty ULC	Coal Valley Resources Inc.	Prairie Mines & Royalty ULC	
Location	Forestburg, AB	Warburg, AB	Hanna, AB	Coronach, SK	Edson, AB	Estevan, SK	
Proven Coal reserves (thousands of tons)	20,375	254,118	30,762	100,078	8,750	179,522	593,605
Probable Coal reserves (thousands of tons)	—	41,880	3,504	7,108	5,900	48,661	107,053
Total proven and probable reserves (thousands of tons)	20,375	295,998	34,266	107,186	14,650	228,183	700,658
Permitted reserves (thousands of tons)	20,375	295,998	34,266	80,372	8,750	182,391	622,152
2015 production (thousands of tons)	1,997	5,745	3,107	3,694	2,133	6,565	23,241
Estimated life of permitted reserves(1)	2023	2067	2025	2036	2020	2046	
Lessor/Ownership	• Private parties • Provincial Government • Freehold	• Private parties • Provincial Government • Freehold	• Private parties • Provincial Government • Freehold	• Private parties • Provincial Government • Freehold	• Private parties • Provincial Government • Freehold	• Private parties • Provincial Government • Freehold	
Lease term	Varies	Varies	Varies	Varies	Varies	Varies	
Current production capacity (thousands of tons)	3,280	5,745	3,638	4,100	4,000	6,400	
Coal type	Sub-bituminous	Sub-bituminous	Sub-bituminous	Lignite	Bituminous	Lignite	
Major customers	• ATCO Power	• Capital Power	• ATCO Power/ TransAlta Corporation	• Sask Power	• Asian and domestic customers	• Sask Power	
Delivery method	Haul trucks	Haul trucks	Haul trucks	Rail	Rail	Haul trucks	
Approx. heat content (BTU/lb.)(2)	7,583	8,398	7,249	5,773	10,800	6,724	
Approx. sulfur content (%)(3)	0.43	0.19	0.50	<.99	0.30	0.40	
Year current complex opened	1956	1988	1984	1978	1978	1973	
Total tons mined since inception (thousands of tons)	153,637	115,515	92,062	129,927	177,339	164,756	



Mining Operation	Prior Operator	Manner of Transport	Machinery	Tons Sold (In thousands) (3) 2013	2014	2015	Total Cost of Property, Plant and Equipment ($ in millions)	Employees/ Labor Relations (1)	Coal Seam
Coal - Canada Segment									
Alberta									
Paintearth	Sherritt International Corporation	• Haul Trucks	• 2 draglines • Cat 993 FEL, Euclid CH160 haulers	—	1,950	1,972	$ 20.1	80 employees 65 represented by IUOE	• Battle River, Paintearth
Genesee	Sherritt International Corporation	• Haul Trucks	• 2 draglines • Cat 789, Komatsu 830E, P&H 4100, haulers	—	3,621	5,745	$ 42.1	130 employees	• Ardley Coal Zone
Sheerness	Sherritt International Corporation	• Haul Trucks	• 2 draglines • Cat 993 FEL, Cat 776 haulers	—	2,490	3,078	$ 31.3	105 employees 86 represented by IUOE	• Sunnynook, Sheerness
Coal Valley	Sherritt International Corporation	• Rail	• 3 draglines • shovels and end dump trucks	—	2,022	2,160	$ 38.1	314 employees 250 represented by IOUE	• Val D'Or, Arbour, Mynheer
Saskatchewan									
Poplar River	Sherritt International Corporation	• Rail	• 2 draglines • FEL, tractor trailer haulers	—	2,617	3,595	$ 34.0	156 employees 134 represented by IBEW 3 by Unifor	• Willow Bunch
Estevan	Sherritt International Corporation	• Haul Trucks	• 6 draglines • FEL and tractor trailer haulers	—	3,705	6,370	$ 110.8	364 employees 292 represented by UMWA	• Souris River, Roche Percee, Estevan
TOTALS Coal - Canada Segment									
				—	16,405	22,920	$ 276.4	1,149 employees (830 union)	

The following Table 25 summarizes operating results for the Coal - Canada Segment. EBITDA is defined as earnings before interest expense, interest income, income taxes, depreciation, depletion, amortization and accretion expense. Adjusted EBITDA is defined as EBITDA before certain charges to income such as restructuring, impairment, debt extinguishment, foreign exchange and derivative losses and/or gains which are not considered part of earnings from operations for comparison purposes to other companies' normalized income. EBITDA and Adjusted EBITDA are key metrics used by us to assess their operating performance and as a basis for strategic planning and forecasting and we believe that EBITDA and Adjusted EBITDA are useful to an investor in evaluating their operating performance. The Canadian Acquisition was completed on April 28, 2014; therefore, there are only eight months of activity for the year ended December 31, 2014. Operating income in 2014 was negatively impacted by $14.2 million of cost of sales related to the sale of inventory written up to fair value in the Canadian acquisition and $9.6 million of restructuring charges. Results of operations were also challenged by continued declines in export prices.

Table 25. Operating results for the Coal - Canada segments in 2015



Coal - Canada Segment Operating Results

	Year Ended December 31,			
			Increase / (Decrease)	
	2015	2014	$	%
		(In thousands, expect per ton data)		
Revenues	$ 430,519	$ 388,664	$ 41,855	10.8%
Operating income (loss)	40,291	(2,670)	42,961	*
Adjusted EBITDA(1)	108,511	79,010	29,501	37.3%
Tons sold—millions of equivalent tons	22.9	16.6	6.3	38.0%

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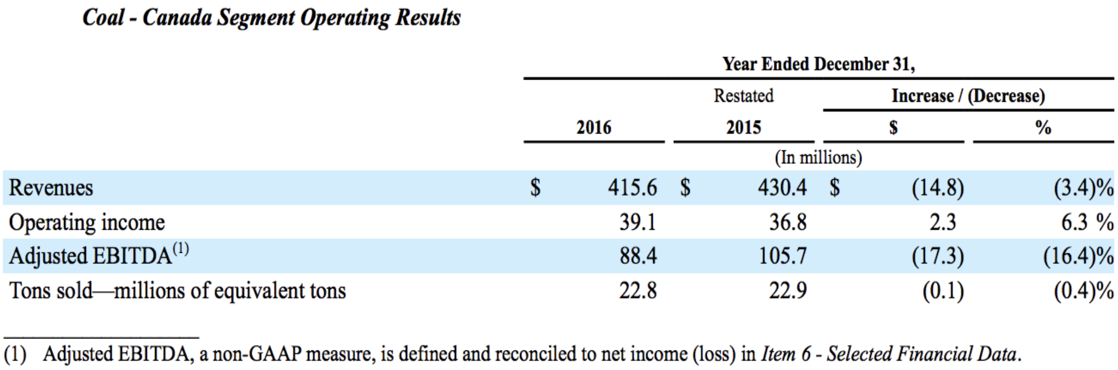
(1) Adjusted EBITDA, a non-GAAP measure, is defined and reconciled to net loss in Item 6, Selected Financial Data.
* Not meaningful

From tables above, we know the tons sold in Coal-Canada segment is 16.6 million in 2014 and 22.9 million in 2015. The Adjusted EBITDA is 79.0 million C$ and 108.5 million C$, respectively. We assume that the tons sold every year is proportional to the revenue. Then if we acquired the number of tons sold of Eastern Mine and Poplar River Mine, we can calculate the revenue of these two mines every year. Since we already know the numbers of tons sold in the Table 24, we get the total revenue of these two mines is 130.5 million in 2014 and 187.2 million in 2015. EBITDA is earning before Interest, Tax, Depreciation and Amortization. Adjusted EBITDA is defined and reconciled to net loss in this table. We use Adjusted EBITDA to calculate the benefit of Estevan and Poplar River Mine, it may be higher than the actual net benefit since we do not know their interests and taxes. In this case, the total benefit will be 30.4 million and 47.2 million in 2014 and 2015.

The following Table 26 provide information about mines in Coal-Canada segments of December 31,2016. Using the same method to calculate the benefit, there are 22.8 ton million coal sold in 2016 and total benefit is 37.8 million. In Table 27, revenue decreased primarily as a result of a weaker Canadian Dollar compared to the prior year. Whether this decrease persists in future periods is dependent upon fluctuations in the Canadian and U.S. Dollar exchange rate. Revenue also decreased because of additional plant downtime in 2016 versus 2015 and decreased tons sold on certain contracts. The decrease in Adjusted EBITDA was driven by accelerated loan and lease receivable payments received in the second and third quarters of 2015 that returned to normal levels in 2016. In addition, the segment encountered record rainfall creating less efficient operating conditions at some facilities and less tons sold as a result.

Table 26. Operating results for the Coal - Canada segments in 2016



Coal - Canada Segment Operating Results

	Year Ended December 31,			
		Restated	Increase / (Decrease)	
	2016	2015	$	%
	(In millions)			
Revenues	$ 415.6	$ 430.4	$ (14.8)	(3.4)%
Operating income	39.1	36.8	2.3	6.3 %
Adjusted EBITDA(1)	88.4	105.7	(17.3)	(16.4)%
Tons sold—millions of equivalent tons	22.8	22.9	(0.1)	(0.4)%

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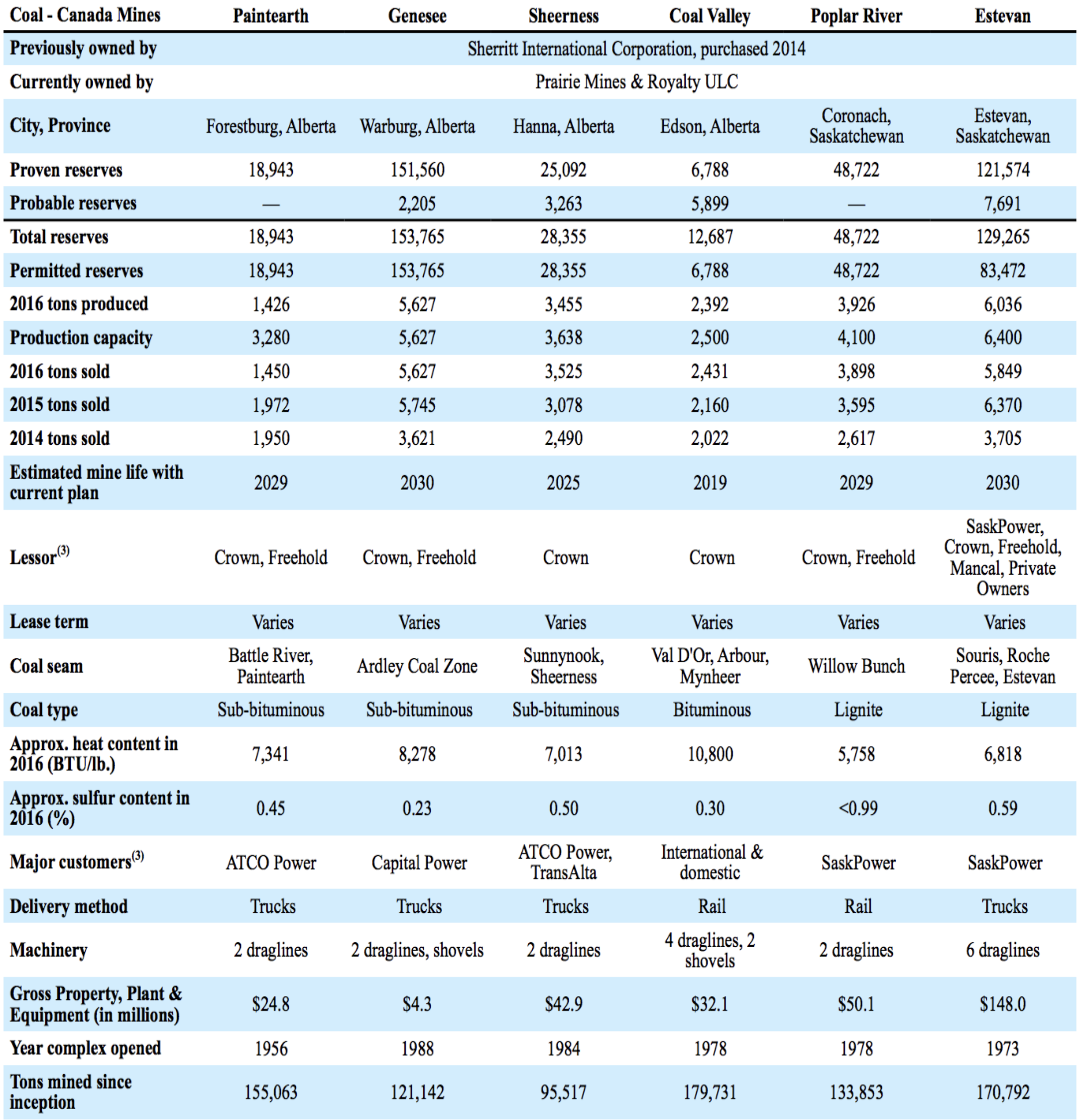
(1) Adjusted EBITDA, a non-GAAP measure, is defined and reconciled to net income (loss) in *Item 6 - Selected Financial Data*.

Table 27. Information about mines in Coal-Canada segments of December 31,2016



Coal - Canada Mines	Paintearth	Genesee	Sheerness	Coal Valley	Poplar River	Estevan
Previously owned by	Sherritt International Corporation, purchased 2014					
Currently owned by	Prairie Mines & Royalty ULC					
City, Province	Forestburg, Alberta	Warburg, Alberta	Hanna, Alberta	Edson, Alberta	Coronach, Saskatchewan	Estevan, Saskatchewan
Proven reserves	18,943	151,560	25,092	6,788	48,722	121,574
Probable reserves	—	2,205	3,263	5,899	—	7,691
Total reserves	18,943	153,765	28,355	12,687	48,722	129,265
Permitted reserves	18,943	153,765	28,355	6,788	48,722	83,472
2016 tons produced	1,426	5,627	3,455	2,392	3,926	6,036
Production capacity	3,280	5,627	3,638	2,500	4,100	6,400
2016 tons sold	1,450	5,627	3,525	2,431	3,898	5,849
2015 tons sold	1,972	5,745	3,078	2,160	3,595	6,370
2014 tons sold	1,950	3,621	2,490	2,022	2,617	3,705
Estimated mine life with current plan	2029	2030	2025	2019	2029	2030
Lessor[3]	Crown, Freehold	Crown, Freehold	Crown	Crown	Crown, Freehold	SaskPower, Crown, Freehold, Mancal, Private Owners
Lease term	Varies	Varies	Varies	Varies	Varies	Varies
Coal seam	Battle River, Paintearth	Ardley Coal Zone	Sunnynook, Sheerness	Val D'Or, Arbour, Mynheer	Willow Bunch	Souris, Roche Percee, Estevan
Coal type	Sub-bituminous	Sub-bituminous	Sub-bituminous	Bituminous	Lignite	Lignite
Approx. heat content in 2016 (BTU/lb.)	7,341	8,278	7,013	10,800	5,758	6,818
Approx. sulfur content in 2016 (%)	0.45	0.23	0.50	0.30	<0.99	0.59
Major customers[3]	ATCO Power	Capital Power	ATCO Power, TransAlta	International & domestic	SaskPower	SaskPower
Delivery method	Trucks	Trucks	Trucks	Rail	Rail	Trucks
Machinery	2 draglines	2 draglines, shovels	2 draglines	4 draglines, 2 shovels	2 draglines	6 draglines
Gross Property, Plant & Equipment (in millions)	$24.8	$4.3	$42.9	$32.1	$50.1	$148.0
Year complex opened	1956	1988	1984	1978	1978	1973
Tons mined since inception	155,063	121,142	95,517	179,731	133,853	170,792

In 2016, the Alberta government took steps to implement some of its proposals under the previously announced Alberta Climate Leadership Plan (the “ACL Plan”). The ACL Plan proposed to phase thet pollution from coal-fired electricity plants in Alberta by 2030. To that purpose, the Government reached agreements with the three owners of the six coal-fired generation power plant units previously scheduled to operate past 2030. These announced agreements provide for the shutting down of these six units by December 31, 2030. Three of these six units are at the Genesee Generating Station, which is fueled by the Genesee mine operations. Two of these six units are at the Sheerness Generating Station, which is fueled by our Sheerness mine operations. These events will adversely affect their potential business at those two mines post 2030. The ACL Plan also proposed the implementation of a carbon levy on fuels that emit GHG. The Climate Leadership Act (the “CL Act”) passed in 2016 introduced a carbon levy on all fuels that emit GHG emissions when combusted. Starting January 1, 2017, the carbon levy rate is $20/tonne of carbon emission released by the fuel when combusted. The rate increases to \$30/tonne effective January 1, 2018. As a result of the carbon levy, starting January 1, 2017, diesel fuel costs to operate our Alberta mines have increased at all sites except the Coal Valley mine. Coal sales to power plants and export sales are exempt from the carbon levy.

The emission penalty under different carbon tax scenarios are listed in Table 23. The carbon levy rate range from 10 C\$/tonne to 50 C\$/tonne of carbon emission released by the coal mining process. Total benefit is the mean of three years. Penalties are calculated under different scenarios.

$$\text{Penalty} = \text{Carbon levy tax rate} \times \text{Total emission}$$

$$\text{Net Benefit} = \text{Total benefit} - \text{Penalty}$$

3.5. Affordable penalty analysis of CCRL

Table 28. Affordable penalty summary of CCRL

Year	Total Output (million C$)	Total Benefit (million C$)	Total Emissions[1] (tonne)
2013	5023.53	225.69	2004000
2014	4105.81	259.35	1879000
2015	2554.18	349.01	2145000
2016	2136.51	413.91	2062000

Note: [1]Carbon dioxide equivalent (CO_2e)

Table 29. Emission penalty under different scenarios of CCRL

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	413.91	2062000	20.62	5.0%
20 C$/tonne	413.91	2062000	41.24	10.0%
30 C$/tonne	413.91	2062000	61.86	14.9%
40 C$/tonne	413.91	2062000	82.48	19.9%
50 C$/tonne	413.91	2062000	103.1	24.9%

3.5.1. Key summary of Co-op Refinery Complex

The Co-op Refinery Complex (CRC) has been in operation for more than 80 years. Since 1935, the CRC has been investing in the local economy of Regina, through major investments, job creation and supporting community initiatives.

From humble beginnings the CRC is now one of Canada's largest refineries. The facility's more than 1100 employees, use leading edge technology to process up to 130,000 barrels of crude oil every day. Our Mission is to Fuel Western Canada, which means continuing to be an economic engine and providing the fuels that power our Western Canadian Economy.

Economic impact of the refinery

- As one of Regina's main economic engines, the CRC employs more than 1100 people and has a base wage payroll of more than $122 million
- The CRC has invested over $2 Billion in Regina's economy since 2012.
- Turnaround maintenance projects put money into the Regina economy for local contractors and suppliers.

Key facts about the refinery

- The CRC processes three types of crude: 1. Sweet Synthetic Crude (30,000 BPD) 2. Sour Synthetic Crude (40,000 BPD) 3. Conventional Heavy Crude (60,000 BPD).
- From the processed crude the CRC produces: gasoline, diesel, propane, butane, sulphur, heavy fuel oil, smelting grade coke, and asphalt.
- The CRC can ship up to 17 million litres of product per day to Co-op gas bars and cardlock facilities throughout Western Canada.
- The CRC blends and ships more than 14 million litres of packaged oil products per year.

History of the refinery

- The Consumer's Co-operative Refinery as it was known, began operation in May of 1935. The original facility produced 500 barrels per day
- In 1951, an expansion of the facility increased production by 5,000 barrels per day.
- In 1953 the "cat" cracker was added to take low value petroleum and make gasoline.
- An expansion in 1974 increased capacity to 50,000 barrels per day.
- In 1988 the $700 million dollar integrated heavy oil upgrader was added, which allowed for the processing of heavy oil.
- The $3 Billion dollar expansion completed in 2012, was at the time the largest capital project in Saskatchewan history and increased capacity to 130,000 barrels per day.

3.5.2. Background of Co-op Refinery Complex

In the 1930s, during the Great Depression, an enterprising group of farmers got tired of paying high prices for fuel and decided there had to be a better way. Eight farmers risked their own money and land to establish their own petroleum refinery to supply what was then a very small chain of Saskatchewan farmer-owned gas stations. That facility went from 500 barrels a day in 1935 – barely enough to supply a few gas stations – to today, a major supplier of Western Canada's fuel needs, producing 130,000 barrels a day. The story of Co-op Refinery Complex is more than a story of an oil refinery. It is a story of leadership. It is a story of success against almost impossible odds. And mostly, it is a story of people and the power they can harness through co-operation.

The Co-op Refinery Complex (CRC) is one of Canada's largest and most productive refineries. The company mission is to fuel Western Canada. In order to Fuel Western Canada in ecological way, the CRC has a responsibility to lead industry in environmental sustainability. The CRC strives to be a leader in environmental compliance and works with industry partners to maintain and set new standards.

Previously known as Consumers Co-operative Refinery Limited (CCRL), the Co-op Refinery Complex is an oil refinery spread over 544 acres (2.20 km^2) located in the city of Regina, Saskatchewan, Canada. The Co-op Refinery Complex is a wholly owned subsidiary and a strategic business unit of Federated Co-operative Limited providing petroleum products to the Co-op Retail System in Western Canada. What began in 1935 as a 500 barrel/day facility has grown to a capacity of greater than 130,000 barrels/day and employs over 900 people. The refinery provides oil products to the member co-operatives of Federated Co-operatives Limited. The complex has completed a $2.9 billion upgrade project (2012) that can increase operations up to 145,000 barrels per day (23,100 m^3/d)

The CRC's neighbors in Regina have grown rapidly and the importance of ensuring that they meet all environmental regulations in order to keep the city protected. To that end, CRC has numerous air quality monitoring stations located throughout the city of Regina that measure air quality and ensure that the refinery is meeting the standards set out in provincial legislation.

Water is also critical to the operations of the Co-op Refinery Complex. The Wastewater Improvement Project utilizes leading-edge technology to clean and recycle wastewater. This addresses the refinery's water needs, which in turn benefits the environment and community. In 2016, Regina's Co-op Refinery Complex spent $200 million on what it's calling an "environmental mega-project", as shown in Figure 9. Its 'Wastewater Improvement Project' plans to clean and recycle all of its wastewater for the purpose of steam production. According to industry experts, it is the first project of its kind in North America. Federated Co-operatives Limited has invested more than $200 million in ensuring the sustainability of our water resources for both the refinery and the City of Regina. This is a significant investment that helps us realize CRC's long term vision focused on sustainability and environmental stewardship.

Figure 9. Co-Op Refinery complex wastewater improvement project

This project will ensure that, over 2 million gallons of wastewater will be cleaned per day; a special blend of live bacteria eats up impurities in the wastewater; spaghetti-like hollow strands of “Zee Weed” filter wastewater to remove suspended solids; high efficiency reverse osmosis (HERO Mode) will be used to clean wastewater for steam production; volatile organic compounds will be removed to reduce emissions and wastewater odours. With the project fully operational-according to industry experts-CRC will be the only North American refinery recycling all wastewater for steam production. CRC will reduce the Refinery’s fresh water use by the equivalent of 3,100 Regina households. This will help fresh water sustainability for the future.

3.5.3. Annual analysis of Co-op Refinery Complex

2013 Annual economic and environmental analysis

Approximately 36.5 million barrels of crude were processed in 2013, a 20 per cent increase over 2012 and the largest volume processed in the history of the CRC. Production was negatively impacted by an extended spring turnaround and by a coker unit fire in February, both of which limited heavy crude processing for 45 days. However, the new Section V led to a record 80,000 barrels per day (BPD) processed during turnaround, maximizing production when one third of the facility was undergoing maintenance. The high demand for product in the fall resulted in purchases of diesel to meet product supply requirements.

For the past three years, CRC has been enhancing a comprehensive Process Safety Management (PSM) system to target safety initiatives and manage operational risks through independent consultation. A PSM system improves safety, reliability and sustainability and includes essential elements to prevent a major release of materials. The system’s implementation phase has begun and will continue over the next few years. A new equipment reliability group was established in 2013 to help improve equipment integrity by assessing current preventative maintenance programs, developing new programs and advising on long-range turnaround plans.

The revamps of four processing units and one utility area were all successfully completed in 2013. All the new equipment was safely started with production from the last unit established in August. To celebrate the completion of the expansion and revamps, CRC held an official grand opening on October 17, 2013, the one-year anniversary of crude feed into the new Section V. The expanded CRC currently has a balanced product capacity of 130,000 BPD and potential for 145,000 BPD. The expansion and revamps increased gasoline production by 30 per cent and diesel production by 25 per cent from 2010 volumes. To utilize the new facility capacity year round, additional commercial and third-party sales have been established. Optimization plans for production and product blending will continue throughout the next several years to ensure that the facility reaches its full potential.

The waste water improvement project is nearing completion and will limit environmental impact by returning treated water into the system and reducing odours and air emissions. Commissioning and start-up activities of the new treatment plant are to commence in spring 2014 with full operation by July 2014.

2014 Annual economic and environmental analysis

In 2014, there were 32.8 million barrels of crude processed in 2014, a 10 per cent decrease from 2013. The decrease is due to a December 2013 explosion in a unit used to manufacture gasoline from propane and butane, as well as an extended spring turnaround. Production increased in June when the section reopened without the unit, leading the refinery to operate at 90 per cent capacity as of year-end. Work to rebuild the damaged unit is expected to be complete in May 2015. Lower production and higher demand for product in the spring and fall resulted in purchases of gasoline and diesel to meet supply requirements.

The refinery continues to improve its risk management system and enhance performance by building a culture of operational excellence. This approach invests in the skills and capacities of its people by focusing on safety, communications systems and talent management. As part of the risk management system, CRC continues to implement a comprehensive process safety management system that improves safety, reliability and sustainability and includes essential elements to prevent a major release of materials.

Improving equipment integrity and reliability remains a major focus, with a new turnaround management group focusing and working on this activity year round. A maintenance excellence initiative is underway to improve equipment reliability through better planning and assessing and adding preventative work.

Optimization plans for product blending and meeting environmental regulatory requirements in the future are in the planning phase. Work on infrastructure and optimization planning will continue throughout the next several years to ensure the five sections of the facility are fully used. Construction on the wastewater improvement project is nearing completion, with commissioning activities underway and full operation targeted for summer 2015. The project will help reduce environmental impact by returning treated water to the system and reducing odours and air emissions.

With construction complete, the Carseland Terminal in Alberta began commissioning activities in 2014. The terminal is expected to become fully operational in winter 2015 and will be capable of distributing up to one billion litres of fuel per year to retail locations in southern Alberta and the British Columbia interior. In partnership with CN Rail and Cando Rail Services, construction of a 250-railcar storage yard north of the refinery began in September and will be complete by the spring of 2015. The yard will improve railcar logistics to ensure continual movement of gasoline, diesel and various byproducts from the refinery.

In 2014, the refinery's permanent workforce grew nearly 10 per cent to 981 employees, with many corporate and non-operational staff moving to a new business office. In addition, there were 154 contractors working on-site throughout the year. This underlines the importance of the refinery to the greater Regina community. The $2.7 billion Section V expansion and revamp project, opened in 2013, generated $5 billion in economic activity in Saskatchewan. The refinery also contributes to local causes, including the local United Way campaign, Coats4Kids initiative and Regina Fire Fighters Burn Fund.

2015 Annual economic and environmental analysis

The CRC spent much of 2015 focused on the safety and reliability of its operations. The CRC has put in place programs such as Operational Excellence, Project Revitalize and Maintenance Excellence that focus directly on developing a culture that supports the refinery's vision. The CRC processed 39.7 million barrels of crude oil in 2015, 21 per cent more than in 2014. However, overall refinery utilization was down because of the late startup of a unit used to manufacture gasoline from liquefied petroleum gas as well as reduced market demand for diesel, which curtailed production.

The CRC had a difficult financial year in 2015. Significant inventory losses resulted from the timing of selling higher-cost inventories in a declining retail market. The U.S. exchange rate played a significant role in the CRC's reduced earnings, as crude is purchased in U.S. dollars.

In the CRC's region, there have been increasing gasoline crack spreads – the difference between the crude oil price and gasoline or diesel selling price – but decreasing diesel crack spreads.

This is significant because, compared to many competitors, CRC is configured to produce more diesel because of the unique demands the Co-operative Retailing System has for diesel. Historically low diesel crack spreads during the 2015 harvest period, when demand for diesel is highest, reduced the overall profitability of the CRC more so than other refineries in this market.

Another market factor that impacted the CRC was a reduction in the heavy crude differential – the difference between the purchase price of sweet light crude and heavy crude. This differential is typically larger than what it was in 2015 and allows the CRC to capture more value from its heavy oil upgrader unit. Other market forces out of the CRC's control added to lower earnings in 2015. Byproducts like butane and asphalt were sold at historically low price differentials compared to the cost of raw crude.

The CRC is looking to address the issues it can control, such as the escalating costs of maintenance and improving process and personnel efficiencies throughout its operations. In addition, major capital projects in recent years are now increasing costs substantially in the form of depreciation.

2016 Annual economic and environmental analysis

In 2016, the Co-op Refinery Complex (CRC) continued to focus on the safety and reliability of refinery operations.

The CRC made solid progress on the reliability of its assets, leading to a better mechanical performance than the previous year. Better performance led to processing a record volume of crude, as 40.4 million barrels were processed in 2016 versus 39.7 million barrels in 2015. Overall gasoline production increased from 18.3 million barrels to 19.7 million barrels. Diesel production, however, was lower by about 1.5 million barrels because of lower market demand for the product.

The CRC, like most North American refineries, is facing difficult market conditions. An oversupply of diesel and gasoline has increased the negative pressure on refinery crack spreads (margins). Weaker demand at the fuel pumps compounded an already oversupplied market as North American refineries continued to build inventory. In addition, a protracted Western Canadian harvest, brought on by unfavourable weather conditions, added to increasing gasoline and diesel inventories. These market dynamics will continue to put pressure on transportation fuels for the foreseeable future.

2016 saw the beginning of increased refining capacity in Western Canada with 25,000 additional barrels of capacity coming online. External pressures and competition will continue to be a hallmark of the refining industry as another refinery in Alberta is scheduled to begin production in late 2017. Pending pipeline project approvals also create uncertainty around Western Canadian crude pricing.

While the market is in a down cycle, the CRC has aggressively gone after areas it can control. Two key areas have been asset reliability and cost-reduction initiatives. These initiatives will allow the refinery to remain competitive and sustainable in difficult market conditions. The CRC also announced the commissioning phase of the Wastewater Improvement Project (WIP) in 2016. This major initiative demonstrates the refinery’s commitment to protecting the environment, its dedication to social responsibility and its drive to become a recognized leader in the petroleum refining industry. The CRC will continue to prepare for the future by focusing on the overall sustainability of its operations.

3.5.4. Overall environmental impacts analysis

FCL has been leading research focused on remediating contamination with little to no environmental footprint for more than 15 years. These efforts have included the use of trees, naturally-occurring fungi and bacteria to transform gasoline and diesel into water, carbon dioxides and plant material, and we have used similar methods to transform fertilizer-based contaminants into non-toxic nitrogen gas.

Carbon footprints are an important measure of an organization’s environmental impacts. FCL operations (including the Co-op Refinery Complex), warehouses and office buildings, feed mills, and distribution fleet have a total carbon footprint of 1.7 million tonnes of carbon dioxide equivalent (tCO_2e); the Refinery makes up 89% of FCL’s carbon footprint. As we continue to grow, FCL is committed to meeting the energy demands of the Co-operative Retailing System while ensuring the continuous improvement of measurement capabilities, practices and policies focused on minimizing our carbon footprint.

On May 25, 2016, the CRC announced that its $200 million Wastewater Improvement Project (WIP) was in the commissioning phase. The WIP uses industry-leading technology to clean and recycle 100 per cent of the CRC wastewater. In addition, the project makes the CRC the only refinery in North America that can clean and recycle wastewater for the purpose of steam production.

The WIP has many benefits for the refinery, the City of Regina and the Province of Saskatchewan. By cleaning and recycling more than two million gallons of wastewater per day, the CRC ensures the future sustainability of its own water supply, while reducing the facility's reliance on the fresh water resources it shares with the citizens of Regina and the province. By reducing the refinery's water consumption, the facility is helping to provide sustainable water resources for future generations.

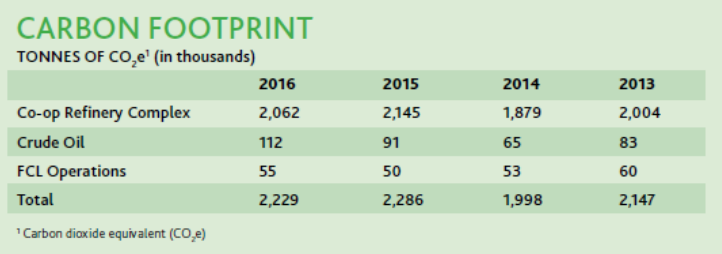
3.5.5. Calculation of affordable penalty

The carbon footprint of CRC and its annual financial data can be obtained from Annual Report of Federated Co-operatives Limited (2013-2016), as shown in Tables 30 and 31. The affordable penalty is calculated following the fulmars below:

$$\text{Affordable penalty} = \text{Total benefit} / \text{Total emissions}$$

$$\text{Total benefit} = \text{payroll} + \text{beneficial margin} * \text{cost of products sold}$$

Table 30. Carbon footprint statistics of FCL



CARBON FOOTPRINT

TONNES OF CO_2e[1] (in thousands)

	2016	2015	2014	2013
Co-op Refinery Complex	2,062	2,145	1,879	2,004
Crude Oil	112	91	65	83
FCL Operations	55	50	53	60
Total	2,229	2,286	1,998	2,147

[1] Carbon dioxide equivalent (CO_2e)

Table 31. Annual analysis data of CRC

Production	2016	2015	2014	2013
Crude oil (million barrels)	40.4	39.7	32.8	36.5
Crude oil price ($/barrels)	52.88	64.34	125.18	137.63
Total output (million $)	2136.51	2554.18	4105.81	5023.53
Employment	896	981	1020	1100

3.6. Affordable penalty analysis of Yara Belle

Table 32. Affordable penalty summary of Yara Belle

Year	Total Output (million C$)	Total Benefit (million C$)	Total Emissions (tonne)
2013	1906	153	658249
2014	2210	182	643971
2015	2236	155	458060

Table 33. Emission penalty under different scenarios of Yara Belle

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	155	458060	4.58	3.0%
20 C$/tonne	155	458060	9.16	5.9%
30 C$/tonne	155	458060	13.74	8.9%
40 C$/tonne	155	458060	18.32	11.8%
50 C$/tonne	155	458060	22.9	14.8%

The world's population is growing and we will be 9 billion people by 2050. By then we need to make 60% more food on the same area of land. Just as humans need essential minerals and nutrients for strong, healthy growth, so do the world's crops. Our core business of fertilizer production is intimately connected with agricultural productivity and food production. The role of fertilizers in food production is usually underestimated. Fertilizers are food for plants. Fertilizers replace the nutrients that crops remove from the soil. Without the addition of fertilizers, crop yields and agricultural productivity would be significantly reduced. That’s why mineral fertilizers are used to supplement the soil’s nutrient stocks with minerals that can be quickly absorbed and used by crops. Crops require a balanced diet of essential nutrients throughout their growth cycle. Many of these essential nutrients can be found in the soil, but often in insufficient quantities to sustain high crop yields. Soil and climatic conditions can also limit a plant’s uptake of nutrients at key growth stages. Plants need 13 essential minerals, all of which play a number of important functions. If any of these is lacking, plant growth and yield suffer.

Each crop needs a different range of nutrients at every critical stage of its development. For example, nitrogen and phosphorous are often more critical at early stages of growth to fuel root and leaf development, whereas zinc and boron are important during flowering. Cereal crops use nutrients for growth, progressively moving them from the roots, leaves and stems into the ear prior to the dying off and harvesting of the grain. Tree crops have different nutrient requirements than field crops. They can store nutrients like nitrogen within their trunk, branches and leaves and then redistribute them at key points during the growth cycle. It is important, however, to supply trees with replacement levels of the nutrients removed in the harvested fruit and those that are critical for growth but can’t be recycled. High-value, high-quality greenhouse crops have perhaps the greatest need for nutritional precision. Top- quality strawberries, lettuce or fruit require a constant and accurately balanced diet. Growers therefore often control crop growth by spoon-feeding plants with what they need in an environment protected from the changing soil and weather conditions.

Thus, in order to meet human nutritional needs in the crops and meat we eat, we need to replace what we take out. The key is to get this balance right and to maintain a level of nutrients in soils that will support our crops without applying excess. Each crop draws down from these reserves and we need to replace them with fertilizers, every year and after every crop. Farmers can turn to Yara for help.

3.6.1 Yara international

Yara International ASA is a Norwegian chemical company. Its largest business area is the production of nitrogen fertilizer, however it also encompasses the production of nitrates, ammonia, urea and other nitrogen-based chemicals.The company was established in 1905 as Norsk Hydr-the world’s first producer of mineral nitrogen fertilizers and demerged as Yara International ASA on March 25, 2004. Yara is listed on the Oslo Stock Exchange and has its headquarters in Oslo. The company has around 13,000 employees, production sites on six continents, operations in more than 50 countries and sales to about 150 countries. The Norwegian government owns more than a third of Yara and is its largest shareholder.

Primary areas

The company has three primary areas of activity:

- Industrial products: a wide range of nitrogen and specialty chemicals and civil explosive solutions.
- Environmental solutions: solutions for NOx abatement, odor control, water treatment and corrosion prevention.
- Agricultural products: complete portfolio of fertilizers and solutions, covering all necessary nutrients for any crop.

Structurally, there are three business platforms and operating segments (Production, Crop Nutrition and Industrial), coordinated through the Supply Chain platform to ensure synergies Production. Production of nitrogen-based products for fertilizer and industrial uses. Crop Nutrition: Sales, marketing and distribution activities around the globe. Industrial: development and processing of environmental solutions and industrial activities. Supply Chain: optimization of energy, raw materials, sourcing, logistics, and shipping.

Yara's agronomists work with local researchers and distributors retailers to ensure that their crop nutrition solutions are tailored to suit local conditions. They also engage with food processing companies to demonstrate that crop nutrition has an impact on food quality and sustainability performance. Thus They also ensure farmers are better prepared to meet consumer needs for quality food.

In addition, they engage with farmers and share knowledge through demonstration trials, regular meetings and seminars as well as providing specific documentation detailing the most suitable crop nutrition management programs for their locations.

Their local presence and market understanding is a combination of global research on crop nutrition combined with local presence and market understanding. In this way they optimize offerings for the local conditions while leveraging global knowledge and experiences from around the world.

Production and solution

Unlike most fertilizer companies, Yara offer a complete range of crop nutrition products. Their fertilizers range from those based on the most widely needed nutrients Nitrogen (N), Phosphorus (P) and Potassium (K) to those incorporating growth and quality enhancing nutrients, such as calcium (Ca) and magnesium (Mg), to micronutrients that help prevent or cure deficiencies resulting from particular soil or crop conditions. If crops lack any of these nutrients, yield and profitability are reduced. That's why yara offer not only a product range that meets all crop nutrition needs, but also crop-specific advice and fertilizer management tools and services.

Product portfolio

The Yara brand is one of the most respected and widely recognized brands in agriculture. Yara partner with farmers worldwide to optimize crop yields, reduce environmental impact and improve crop quality and nutritional value. Our fertilizer products are precisely formulated to provide targeted nutrition to suit each specific situation. We recognize that soils, crops and climates are unique and that different fields and crops have different nutritional requirements. Our approach is always to properly identify the needs, meet those needs effectively, and to do all of that in an environmentally sustainable way.

Yara's product portfolio, sold as six main global brands, represents the most comprehensive product portfolio in the industry. This is how a successful crop is built-by bringing together global crop knowledge and regional expertise to provide a premium crop nutrition range that's precisely focused on crop requirements.

(1) YaraBela™

"Bela" derives from the Old Norse word "beyla", meaning fertility. The YaraBela nitrogen fertilizer range is a proven solution for the strong, prolonged growth of fertile crops; products that have been tried, tested and proven as a result of practical experience across a range of crops worldwide.

YaraBela nitrogen fertilizers comprise cost-effective sources of nitrogen and calcium to fuel growth and productivity. Most commonly packaged as bulk products, YaraBela fertilizers are widely used as dry applications on large-scale field crops. They supply a balanced source of nitrogen, usually as a mix of ammonium and nitrate forms, to maximize soil fertility and boost growth processes and yield. This combination provides the best of both worlds; rapidly available nitrate for immediate growth, and slow-release ammonium for prolonged plant development. YaraBela nitrogen fertilizers provide consistent, proven crop performance year-in and year-out across a wide range of crops and climatic conditions.

(2) YaraLiva™

"Liva" is the Old Norse word for "life". YaraLivaYaraLiva fertilizers are a comprehensive range of calcium nitrates that help ensure high-value, highly marketable produce. Quite simply, they are a range of high-quality fertilizers that optimize cash-crop performance and produce food that satisfies even the most demanding growers and consumers. They provide fast acting nitrate-N, alongside strength building calcium and boron. In combination, these nutrients fuel prolonged growth. At the same time, plants and trees treated with YaraLiva-branded fertilizers are naturally healthier and less sensitive to stress during growth. Then, critically, in the build-up to harvest, YaraLiva fertilizers improve the size, strength and appearance of the fruit, tuber, leaf or lettuce.

The end result is blemish-free produce that will store longer and which is less susceptible to damage, disease or rotting and visibly more desirable, colorful, fresher and highly nutritious.

YaraLiva™ TROPICOTE™
19% Calcium (26,3% CaO)
15.5% Nitrogen (14.4% nitrate 1.1% ammonium)

YaraLiva™ TROPICOTE™ is a market-leading premium branded fertilizer for high-value crops. Used right from the start and as a regular top dressing, it fuels growth in high-value cash crops providing nitrogen and calcium when the crop needs it, building strong, highly marketable produce.

(3) YaraMila™

"Mila" is derived from the Old Norse word "mikla," meaning success. YaraMila complex fertilizer is a comprehensive range of the most essential plant nutrients – a combination of nitrogen (N), phosphorus (P) and potassium (K) designed to maximize crop yield and quality. Formulated to meet precise crop requirements, these NPKs are some of the most highly efficient sources of N, P and K available. Each YaraMila particle contains precisely tailored amounts of NPK. So, when accurately applied to a crop, YaraMila fertilizers ensure the accurate, complete addition of these major nutrients.

In addition, growers can select from YaraMila products that also contain secondary and micronutrients essential for specific crops. These include essential nutrients, from magnesium (Mg) and sulfur (S) to manganese (Mn) and zinc (Zn). As a result, by using YaraMila products, growers can ensure balanced nutrition throughout the growing season, ensuring that yield and quality do not suffer.

YaraMila-branded fertilizers utilize a balanced nitrogen source, provide a unique phosphate formulation for easier absorption and ensure efficient nutrient release. While there are a number of NPK brands on the market, YaraMila is the only product range that offers complete crop success based on a long tradition of quality, giving and expert advice from a global leader in the field of crop nutrition.

YaraMila COMPLEX:

12% Nitrogen (5% Nitrate - 7% Ammonium), 11%Phosphorus(P_2O_5), 18% Potassium (K_2O) Plus Magnesium (2.65% MgO), sulfur (19.9% SO_3) and trace elements Zn (0.02%) and B (0.015%). YaraMila COMPLEX is one of the most complete compound NPK fertilizer packages available. It is typically applied at the beginning of the crop cycle, providing a basic balanced nutrient package that is used throughout the crop growth cycle.

(4) YaraTera™

"Tera" is derived from the Old Norse word "Tæra", meaning feeding. YaraTera is a complete range of fully water-soluble fertilizers for fertigation which, together with YaraLiva™ CALCINIT™ and the YaraTera™ Fertigation Software, the Yara Water Solution and Megalab, offer a full crop solution for fertigation.

YaraTera includes a comprehensive range of fully water-soluble products, including NPKs, straights, chelates, liquid fertilizers and biostimulants. When combined with an efficient irrigation system, both nutrients and water can be managed to obtain the maximum yield and quality.

Importantly, the products are easy to handle and apply to a wide range of crops. The YaraTera products are also supported by Yara's vast knowledge of application strategy, fertigation training programs and a set of tools and services to help farmers with everyday operations.

(5) YaraVera™

"Vera" is derived from the Old Norse word "vekra," which means "to enliven or invigorate". YaraVera nitrogen fertilizers are cost-effective, highly concentrated and highly efficient sources of urea.

With a nitrogen concentration of 46 %, YaraVera fertilizers ensure strong, sustained growth over a prolonged period through efficient nutrient release. They can be applied to the soil as solid granules, in solution or to certain crops as a foliar spray. When properly applied, YaraVera fertilizers support optimum-efficiency plant growth leading to some of the highest yields possible. YaraVera's superior quality and highly concentrated form also help to reduce handling, storage and transportation costs.

(6) YaraVita™
"Vita" is derived from the Old Norse word "vita," meaning knowledge. YaraVita fertilizer is a complete line of nutrient products that ensure crops obtain everything they need and that growers gain more from optimally performing crops.

Each YaraVita formulation delivers a specific nutrient or nutrient mix exactly when and where the crop needs it, boosting crop performance. This includes accurately applied and essential doses of micronutrients either as straight products or combi-mixtures. In addition, the YaraVita range includes formulations that back up supplies of major or secondary nutrients during periods when these are unavailable from other sources. YaraVita products supply complete plant nutrition and are easy, safe and convenient to use.

High-quality chelates from the YaraVita range are ideal for use in fertigation or soil-less systems. They are formulated to minimize interaction with other elements within the nutrient solution and to overcome problems relating to both soil and water pH. This means maximum nutrient availability.

Field Applied Nitrogen Fertilizer

Nitrogen is essential for healthy plant growth and good yield. Straight nitrogen fertilizers are often the major source of this important nutrient. Nitrate forms of nitrogen are most swiftly absorbed by crops, which is why they are commonly used when a fast response is needed. In contrast, ammonium and urea based fertilizers need to be transformed by microbe activity in the soil before plants can absorb them. Therefore they are more commonly used where a more gradual uptake of nutrients is needed.

Calcium ammonium nitrate (CAN), is a mixture of AN and calcium magnesium carbonate. It contains nitrogen that can be immediately absorbed by plants. Their range of CAN products has nitrogen concentrations of 25 to 28 percent. CAN also contains 10 percent calcium (Ca), or lime, which helps to neutralize soil acidity. Ammonium nitrate (AN) is a more concentrated source of nitrogen containing 33.5 percent to 34.5 percent N. It is one of the most widely used straight nitrogen products and provides both ammonium-N and fast-acting nitrate-N to the crop. Urea is the most concentrated solid nitrogen fertilizer available (46 percent N), and has become the world's major source of nitrogen. Urea ammonium nitrate solutions (UAN) contain 28 to 32 percent N and are used where distribution and application techniques suit liquid fertilizer use. Ammonium sulfate (AS) has relatively low nitrogen content (21 percent N). It also contains 24 percent sulfur (S).

In addition to nitrogen fertilizers, yara supply various composite fertilizer products. These supply several chemically combined major nutrients, most commonly nitrogen (N), phosphorus

(P) and potassium (K). Some also contain secondary and micronutrients. NPK products have consistent size and mass, which makes accurate spreading easier. Blended products mixtures of straight fertilizersare also widely available. Yara's products are often utilized in high-quality blends.

Yara also supply field-grade calcium nitrate fertilizers for cash crops. These products deliver their 33 percent calcium content throughout the season to ensure high-quality fruit and vegetable production for growers and consumers. Potassium nitrate can also be a valuable product, for example in late-season applications to fruit. Potassium nitrate range is of high quality and easy to handle.

Fertigation

"Fertigation" is the combined application of water and nutrients to a crop - a mix of fertilizer and irrigation. It can be adapted to all types of crops, but is most common in cash-crop segments, rather than broad-acre or arable crops.

Yara have a wide range of fertigation and liquid fertilizers to meet any crop situation. Our full range of essential nutrients can be used in drip irrigation, sprinkler systems or pivot agriculture. Yara's fertigation products include high-quality calcium nitrate, potassium nitrate and a full range of micronutrient chelates. They're used in soil and fertigation applications, and can also be used as a source material for foliar products.

Chelates help overcome many problems associated with metallic ion tie-up in the soil by taking a positively charged metallic ion and turning it into a negative form that is less readily rendered unavailable in the soil.They do so by "sealing" the nutrient in a protective structure that keeps it within the soil solution, effectively preventing nutrient loss.

Foliar

Foliar applications are used for targeted input at the crop's key growth stages. By spraying directly onto the crop, nutrient availability can be controlled and soil interaction avoided.Foliar sprays are particularly useful for accurately applying relatively low doses of micronutrients. However major and secondary nutrients are sprayed at key growth stages to supplement soil-applied nutrients, for example calcium sprays on apples during fruit development.Foliar fertilizer aplication. Foliar products need to be correctly formulated, so as to maximize effect and minimize the risk of damage when sprayed onto leaves or fruit.

Yara utilizes suspension concentrates, solutions and powders, which provide controlled nutrient release over a longer period than unformulated products. Yara also provide pure, often food- or pharmaceutical grades of nutrients and a wide range of co-formulants that ensure safe use and highly efficient nutrient uptake, biological activity and longevity.They are also formulated with stickers, spreaders and absorption agents that maximize efficacy and crop safety, thereby prolonging balanced growth.

3.6.2 Yara belle plaine

Yara has operated in Canada for more than 20 years, with facilities strategically located in both the east and west to optimally serve its Canadian and Northern U.S. customers.

In 1996, Yara (Norsk Hydro at the time) purchased Nutrite, a company in Eastern Canada. Nutrite operated several bulk blending plants as well as a year-round import terminal in Contrecoeur, Quebec. Today, the terminal in Contrecoeur is the premier import terminal in eastern Canada and has storage capacity of 160,000 metric tonnes of dry fertilizer. It is ideally situated on the south shore of the St. Lawrence River (about 1 hour east of Montreal) and is accessible to customers in the main agricultural regions in eastern Canada and northeastern US. On October 1, 2008, Yara International ASA purchased Saskferco, a production facility established in 1992 in Belle Plaine. It is one of North America’s newest nitrogen fertilizer facilities and is, in fact, one of the largest single line granulation facility on the continent. Yara’s Belle Plaine production facility is ideally situated in close proximity to its core markets in western Canada and the northern U.S.

The site has the following production units: One ammonia plant, one nitric acid plant and one urea granulation plant. Yara Belle Plaine has the largest single line granulation plant in North America. Yara Belle Plaine produces an average of 3,000 tons of urea, 700 tons of UAN and 1,900 tons of ammonia per day. The majority of the ammonia produced is used in the production of UAN and granular urea, however some product is sold for agricultural purposes during peak ammonia seasons. Yara Belle Plaine is currently undergoing an expansion of its urea and ammonia production plants.

The emission penalty under different carbon tax scenarios are listed in Table 33 . The carbon levy rate range from 10 C$/tonne to 50 C$/tonne of carbon emission released by the coal mining process. Total benefit is the mean of three years. Penalties are calculated under different scenarios.

$$\text{Penalty} = \text{Carbon levy tax rate} \times \text{Total emission}$$

$$\text{Net Benefit} = \text{Total benefit} - \text{Penalty}$$

3.7. Affordable penalty analysis of Evraz

Table 34. Affordable penalty summary of Evraz

Year	Total Output (million C$)	Total Benefit (million C$)	Total Emissions (tonne)
2015	890	115	216750
2016	749	113	210654
2017	616	66.6	165648

Table 35. Emission penalty under different scenarios of Evraz

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	66.6	165648	1.65	2.5%
20 C$/tonne	66.6	165648	3.3	5.0%
30 C$/tonne	66.6	165648	4.95	7.4%
40 C$/tonne	66.6	165648	6.6	9.9%
50 C$/tonne	66.6	165648	8.25	12.4%

EVRAZ is a vertically integrated steel, mining and vanadium business with operations in the Russian Federation, USA, Canada, Czech Republic, Italy and Kazakhstan. EVRAZ is among the top steel producers in the world based on crude steel production of 14 million tonnes in 2017. A significant portion of the company's internal consumption of iron ore and coking coal is covered by its mining operations. The Group is listed on the London Stock Exchange and is a constituent of the FTSE 100. EVRAZ employs approximately 80 000 people. Their principal activities are: (a) Manufacturing steel and steel products; (b) Iron ore mining and enrichment; (c) Coal mining; (d) Manufacturing vanadium products; (e) Trading operations and logistics. The company's consolidated revenues for the year ended 31 December 2017 were C$14119.24million, and consolidated EBITDA amounted to C$3421.9 million.

EVRAZ can be described in simple six sentences: (a) It is a vertically integrated global steelmaker; (b) It is one of the lowest cost global steel producers; (c) It is the market leader in construction steel products; (d) It is the leading global supplier of rails; (e) It is one of the world leaders in the production of vanadium; (f) It has geographically diversified business.

EVRAZ began its evolution in 1992. A group of Russian scientists and engineers established EvrazMetall, a company specializing in trading steel products and supplying raw materials and equipment to Russian steel mills. Subsequently, EVRAZ has experienced a series of acquisitions and expansion. In 2004, it acquired Kachkanarsky Ore Mining and Processing Plant (EVRAZ KGOK) and Evrazruda Iron Ore Processing Complex. In 2005, it acquired Palini & Bertoli in Italy. In 2007, EVRAZ acquired a stake in Highveld Steel and Vanadium Corporation, South Africa and Nikom, a ferrovanadium producer located in the Czech Republic. It also acquired a number of Ukrainian assets, including – Dnepropetrovsk Iron and Steel Works, Sukha Balka Iron Mine, Dneprokoks and Bagleykoks. In 2008, EVRAZ acquired IPSCO’s plate and tubular business, located in Canada. In 2010, EVRAZ’s employee headcount has reached 110,000 worldwide. EVRAZ won the tender to develop the Mezhegey coal deposit in the Republic of Tyva (Russia). And it acquired Inprom, a Russian steel distribution network. EVRAZ achieved premium listing on the London Stock Exchange in November 2011. In December 2011 the company became a constituent of the FTSE index. In 2013, EVRAZ launched light-section rolling mill in Kostanay, Kazakhstan. In 2016, EVRAZ launched commercial production at EVRAZ new mine in the republic of Tyva - "Mezhegeyugol".

EVRAZ’ top environmental priorities include decreasing air emissions. The primary air emissions comprise nitrogen oxides (NOx), sulphur oxides (SOx), dust and volatile organic compounds.

In 2011, before adopting its five-year environmental targets, the Group had already substantially reduced its air emissions. The current strategy for reducing air emissions envisages upgrading gas treatment systems, introducing modern technologies and eliminating obsolete equipment. In 2016, key air emissions were down by 3.5 thousand tonnes (or 2.6%) compared with 2015.

The management has also decided to conduct a like-for-like analysis that rebases the target by excluding data related to divested assets (EVRAZ VGOK, EVRAZ Vitkovice Steel, Evrazruda’s Krasnoyarsk mines, EVRAZ ZSMK’s central power plant, EVRAZ Highveld and EVRAZ NTMK’s Nizhnesaldinsky metal mill), which shows that key air emissions at current assets have risen by 18.8% since 2011. This has been driven primarily by an increase in sulphur content in the coal and ore used at EVRAZ ZSMK's power and sinter plants, which has resulted in higher SOx emissions, and higher NOx emissions at EVRAZ KGOK. However, EVRAZ' emission reduction initiatives are expected to decrease key air emissions over the coming years.

EVRAZ' operations also generate carbon dioxide and other greenhouse gas (GHG) emissions. The Group understands the urgency of climate change prevention and supports the global effort to reduce the emission of GHGs into the atmosphere. In compliance with the Companies Act 2006 (Strategic and Directors' Report) Regulations 2013, EVRAZ measures the full GHG emissions its facilities and has taken part in the CDP Climate Change Programme since 2011.

The Group measures direct emissions of all seven "Kyoto" GHGs1 and indirect emissions from the use of electricity and heat. The inventory approach2 was based on the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) and the WRI/WBCSD GHG Protocol Corporate Accounting and Reporting Standard. EVRAZ reports data in tonnes of carbon dioxide (CO_2) equivalent (tCO_2e), calculated using the IPCC Fourth assessment report (2007) global warming potentials.

Data on GHG emissions were collected for 2016 and compared with 2013-2015 levels. The Steel segment continues to generate more than half of gross GHG emissions from Group operations. Nearly 92% of the Coal segment's full emissions come from fugitive methane (CH4) leakage, which is caused by methane ventilation from underground mines and postmining emissions from coal.

Overall GHG emissions from EVRAZ' operations fell by about 5% year-on-year in 2016. Emissions of CO_2 remain at the 2015 level due to the cumulative effect of a minor increase at the Steel segment (up around 0.4 million tCO_2e) and the cease in operations at EVRAZ Highveld Steel and Vanadium in 2016. In the Coal segment, CH4 emissions dropped by 10% due to a lower methane content in the coal mined as well as lower coal extraction at some mines.

All told, EVRAZ brought down its Scope 1 emissions by 2% and its Scope 2 emissions by roughly 19%, due to the cease in operations at EVRAZ Highveld Steel and Vanadium in 2016 (which accounted for some 6%) and lower volumes of energy purchased by EVRAZ NTMK and EVRAZ ZSMK in 2016.

EVRAZ reports an intensity ratio relating its annual GHG emissions to its activities: total Scope 1 and 2 emissions per consolidated revenue for the Group overall and each operating segment. In addition, specific emissions in the Steel segment per tonne of steel cast for 2013-16 are compared with average specific emissions of World Steel Association members for 2015. Higher specific GHG emissions in the Steel segment may be due to the key role played by integrated iron and steel works (which inherently emit more GHGs than rolling mills) in EVRAZ' steel production.

EVRAZ strives to make efficient use of water resources and prevent any negative water quality impacts through environmental incidents. In 2016, almost 84% of EVRAZ total water intake for production needs was from surface sources, including rivers, lakes and reservoirs – the same result as in 2015.

In 2016, the ongoing water management performance improvement programmes at EVRAZ' operations began to show their first environmental benefits, evidenced by the 3.3% year-on-year reduction in fresh water consumption (down by 11.3 million cubic metres compared to 2015).

Given the HSE Committee's decision to re-base the target by excluding data related to disposed assets, fresh water consumption was down by 78.2 million cubic metres (17.3%) compared with the 2011 adjusted baseline. Water discharge was reduced by 45.15 million cubic metres over 2012-2016.

Water pumped from mines (dewatering) is not included in the fresh water consumption target, although pumped water is partly used for technological needs. In 2016, 20.3 million cubic metres of mine water were pumped out and used, compared with 20.5 million cubic metres in 2015.

Mining and steelmaking operations produce significant amounts of waste, including waste rock, spent ore and tailings (waste from processing ore and concentrates). EVRAZ aims to reduce the amount of waste that it produces, re-use natural resources where possible and dispose of waste in a manner that minimizes the environmental impact while maximizing operational and financial efficiency.

In line with the Group's strategy to reduce waste storage volumes and enhance waste disposal, EVRAZ enterprises regularly review opportunities for waste recycling and reuse.

In 2016, EVRAZ steel mills generated 9.65 million tonnes of metallurgical waste (slag, sludge, scale etc) and recycled or reused 11.59 million tonnes. Overall, the Group recycled or reused 120.1% of non-mining waste and by-products in 2016, compared with 126% in 2015.

The main reason for the lower waste recycling rate is that EVRAZ ZSMK sold its slag processing plant and slag disposal facility to an external recycling company. EVRAZ' strategy for dealing with nonhazardous mining wastes, such as depleted rock, tailings and overburden, is to use them where possible for land rehabilitation and the construction of dams or roads. In 2016, 18.2% or 28.7 million tonnes of such waste material were reused, compared with 17% or 24.6 million tonnes in 2015. All non-recyclable waste is stored in facilities that are designed to prevent any harmful substances contained in the waste from escaping into the environment. Safety at such facilities is monitored extremely closely, and steps have been taken to mitigate as far as possible any danger to third parties in an emergency.

The EVRAZ conscientiously fulfills its social responsibility. EVRAZ contributes to local economies in every way it can, supporting the communities in which it operates. They take the social responsibilities seriously. These include good ethical behavior, concern for employee health and safety, care for the environment and community involvement. It is an integral part of how they conduct the business, make decisions, and set the priorities.

EVRAZ has many branch companies. EVRAZ North America is proudly based in the United States and a wholly owned subsidiary of EVRAZ plc (traded on the London Stock Exchange), which serves as one of the largest vertically integrated steel and mining businesses in the world. As a leading North American producer of engineered steel products for rail, energy and industrial end markets, they deliver a broad selection of specialty steel solutions to meet customers' demands in the United States and Canada.

EVRAZ North America has six production sites located in the United States (Portland, Oregon; Pueblo, Colorado) and Canada (Regina, Saskatchewan; Calgary, Camrose and Red Deer, Alberta). They are the largest North American producer by volume in the rail and large diameter pipe markets. They also hold leading positions in the West Coast plate as well as the Western Canada oil country tubular goods and small diameter pipe markets. It is a leading producer of engineered steel products for rail, energy and industrial end markets with deep American roots and a long legacy of operational success in the United States and Canada.

The diverse range of manufacturing capabilities allows them to produce a wide array of specialty steel products: plate, coiled plate, welded and seamless pipe for oil and gas applications, rail and wire rod and bar. They take a dynamic approach to manufacturing, using the geographic accessibility and production flexibility of our facilities to respond quickly to changes in the market for maximum efficiency and cost savings. The Product Technology Centers in Pueblo and Portland and the Research and Development complex in Regina enhance their ability to develop high strength steel products for the most demanding applications. They have a long legacy of leadership in the communities where they operate and continue to explore growth opportunities to expand the operations in the United States as well as Canada.

EVRAZ North America sells nine categories of goods, Steel plate, Coiled plate, Premium rail, wire road and coiled reinforcing bar, Seamless Pipe, Line Pipe, OCTG Casing and Tubing, EVRlock Conections and Recvcina.

Steel plate is in railcars, barges, ocean-going vessels, industrial equipment, tanks and pressure vessels, large diameter pipe for oil and natural gas transmission, wind towers, bridges, armored vehicles and many other applications. EVRAZ Regina and Portland collectively produce over 500 grades and specifications of steel plate. They are known for the ability to provide products and services that consistently satisfy our customers' expectations. Their hot-rolled plate, strip mill plate and heat-treated plate spans a wide variety of grades and sizes. They produce as-rolled carbon, high-strength-low-alloy and alloy grades, plus heat-treated carbon and alloy grades. The ability to turn and roll product to width before they finish the length allows them great flexibility in producing the customers' specific dimensions.

EVRAZ Portland and Regina hot-rolled coil capabilities include carbon, high-strength-low-alloy and alloy grades for welded pipe and tubing as well as cut-to-length sheet and plate. Their coil products come in thicknesses up to 5/8" in a wide range of custom and standard sizes.

EVRAZ Rocky Mountain Steel is vertically integrated, manufacturing and providing virtually all of the billets for its Rod and Bar mill. The products exhibit excellent drawability, tensile uniformity, microstructure and chemical control. This provides their customers with superior, consistent performance and excellent value. Because wire rope is a premium quality product with demanding requirements, it is produced to rigorous internal standards which meet or exceed industry specifications. Compositional aspects such as segregation control are achieved by controlled melting, casting and rod cooling practices. Surface decarburization is controlled by the walking beam reheat furnace practices, and the ultra-heavy duty no-twist V-Block ensures exceptional dimensional control of the rod, which permits more accurate prediction of finished wire properties. Precise controlled cooling of the rod is possible via the modern Stelmor cooling conveyor. The processes produce carbon steel grades of 1045 up to 1093 to meet the tensile refined grade requirements. EVRAZ Rocky Mountain Steel produces 5.5 mm high-carbon rods to meet the high quality standards required by our customers. All heats are carefully analyzed for chemical components and the wire rod is critically inspected for surface and internal defects. Each heat of steel is processed as a single unit under controlled conditions. As for the PC Strand, Due to the critical nature of this product, EVRAZ Rocky Mountain Steel employs selective scrap control along with electromagnet stirring both in the mold and below the mold to ensure our products meet the demanding requirements of this application. Tensile Refined grades are typically employed in these applications due to the requirement of precise final wire/strand tensile strength.

EVRAZ Rocky Mountain Steel's Seamless Pipe Mill boasts a highly skilled work force, superior process control from start to finish, advanced non-destructive testing techniques and sophisticated equipment. This allows them to supply the customers with the highest quality product possible. To make OCTG, home-produced cast rounds are cut into billets and carefully inspected for surface quality, then uniformly re-heated in a specially designed rotary hearth furnace. A piercing mill method is used for piercing and expanding the solid round billets and rolling into tubes.

EVRAZ is North America's leading supplier of large diameter line pipe for oil and natural gas transmission, and the only supplier of fully "Made in Canada" LD pipe. They are also a leading producer of small diameter line pipe for construction, energy exploration and production. Produced at EVRAZ Regina, Portland and Camrose, double-submerged arc welded (DSAW) large diameter straight seam and spiral pipe for oil and gas transmission is available with external fusion bonded epoxy and abrasion-resistant overlay coatings, as well as internal epoxy coating. Electric resistance weld (ERW) pipe is produced at EVRAZ Regina, Camrose, Calgary and Red Deer. It is available with external polyethylene, fusion bonded epoxy and abrasion resistant coatings, as well as internal epoxy coatings.

EVRAZ is the largest producer of oil country tubular goods in Western Canada. They have operations in Camrose, Calgary and Red Deer, Alberta; and Regina, Saskatchewan. They also have the only OCTG heat treat line in the region, giving us the ability to produce pipe used in demanding, non-conventional shale and oil sands exploration.

EVRAZ Recycling is the largest metal scrap recycler in western Canada with 13 facilities across the prairies. They also have three facilities in the U.S. - one in North Dakota and two in Colorado. They buy, process and sell a wide range of ferrous and non-ferrous materials, and offer a variety of metal recycling and other services including auto wrecking yards that provide a great selection of low cost parts on a self-serve basis.

With a strong legacy that dates back to 1956, EVRAZ Regina is the largest steel company in western Canada. They make steel plate and coil, small and large diameter pipe, and oil and gas well tubing for the energy sector. Regina facilities include: Steelmaking and Rolling Mills, Tubular Mills and R&D Center.

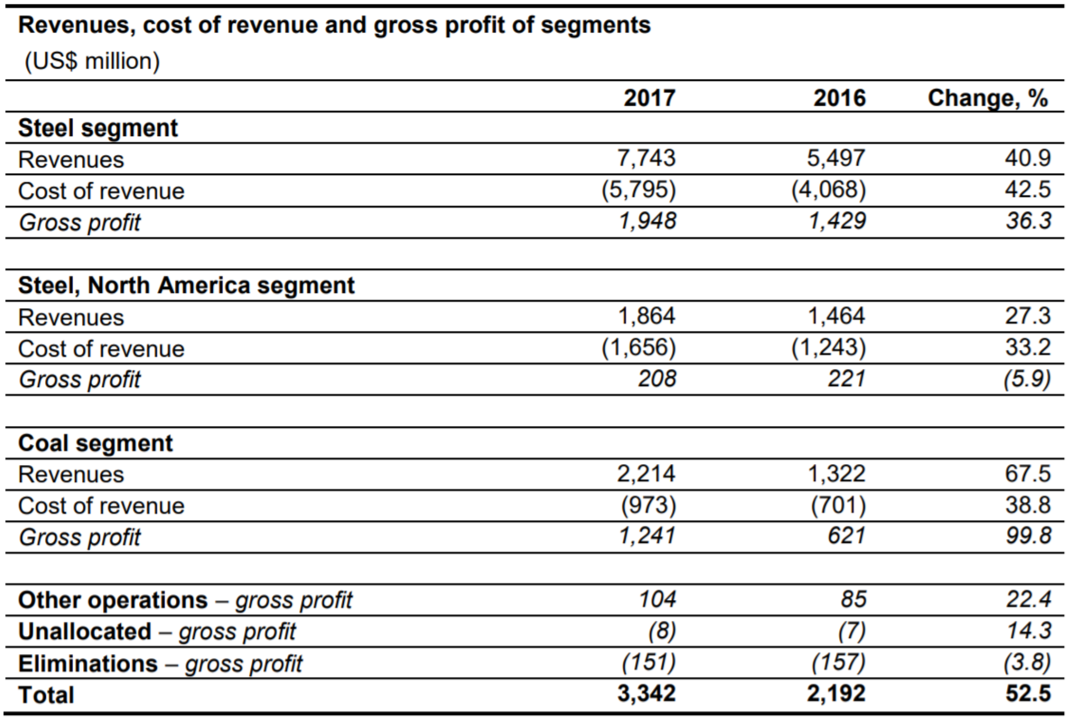
Operating since 1961, the Regina Steelmaking complex produces carbon steel slabs, discrete plate and coil. Scrap metal is converted to liquid steel in two electric arc furnaces, and then cast into slabs. The slabs are hot rolled, primarily into coiled plate for the pipe facilities. The products include steel plate and coiled plate, which are introduced in the previous section.

The Canadian Tubular operations are important suppliers to the energy tubular market, and the only producer of "100% Made in Canada" pipe. Plate and coil produced from steel manufactured and rolled on site is converted into tubular products. They make 24" to 60" diameters at five spiral pipe mills; and 2" and 24" diameters at two straight seam ERW mills. The products include OCTG Casing and Tubing, Line Pipe and ASTM A252.

Based on the annual report of EVRAZ, we are able to calculate the total output and total benefit of EVRAZ Regina in 2015, 2016 and 2017. In its full-year financial results for 2017, EVRAZ reported an increase of 40.4% year-on- year in consolidated revenues, which were US$10,827 million compared with US$7,713 million in 2016. This performance was driven partially by higher volumes but mostly by an upswing in prices for steel and coal products amid more favorable market trends. The Steel segment's revenues (including intersegment) increased by 40.9% year-on-year to US$7,743 million, or 63.0% of the Group's total before elimination. The growth was mainly attributable to higher revenues from sales of steel products, which rose by 39.8% year-on-year, largely due to an upturn in average sales prices of 38.6% that was underpinned by favorable market conditions. Steel product sales volumes remained strong in 2017 (+1.2% y-o-y).

The Steel, North America segment's revenues grew by 27.3% year-on-year. Prices rose by 18.7% and volumes climbed by 12.7%, boosting the segment's revenues from sales of steel products by 31.4%. The key drivers of this growth were an improved demand for oil country tubular goods (OCTG) following a recovery in oil prices and a stronger demand for railway products. The following Table 36 provides information about unrealized profits or losses that relate to the inventories produced by the Steel segment on the Steel, North America segment's balance sheet, and coal inventories produced by the Coal segment on the Steel segment's balance sheet:

Table 36. Information about revenues in Steel, Steel, North America and Coal segments



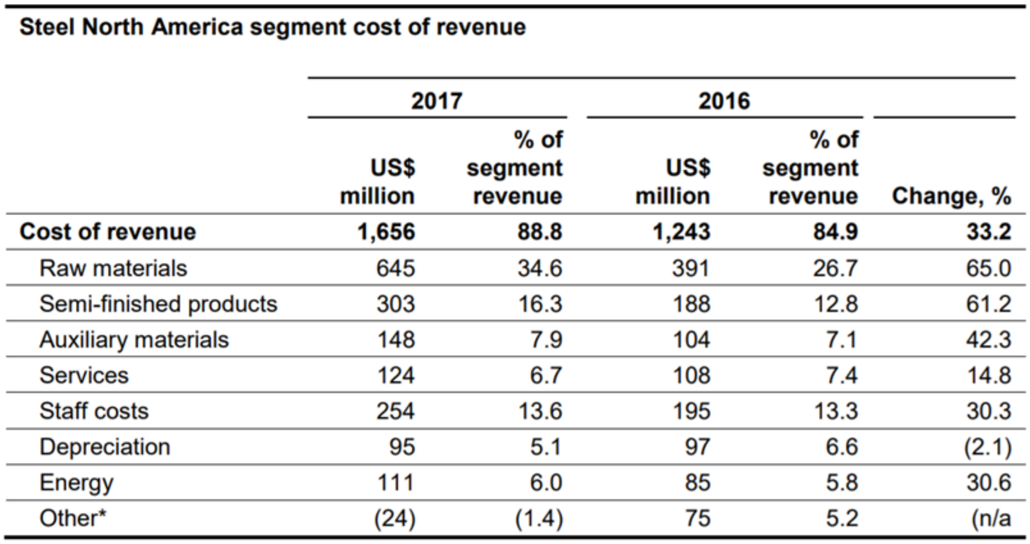
Revenues, cost of revenue and gross profit of segments
(US$ million)

	2017	2016	Change, %
Steel segment			
Revenues	7,743	5,497	40.9
Cost of revenue	(5,795)	(4,068)	42.5
Gross profit	*1,948*	*1,429*	*36.3*
Steel, North America segment			
Revenues	1,864	1,464	27.3
Cost of revenue	(1,656)	(1,243)	33.2
Gross profit	*208*	*221*	*(5.9)*
Coal segment			
Revenues	2,214	1,322	67.5
Cost of revenue	(973)	(701)	38.8
Gross profit	*1,241*	*621*	*99.8*
Other operations – *gross profit*	*104*	*85*	*22.4*
Unallocated – *gross profit*	*(8)*	*(7)*	*14.3*
Eliminations – *gross profit*	*(151)*	*(157)*	*(3.8)*
Total	**3,342**	**2,192**	**52.5**

In 2017, the Steel, North America segment's cost of revenues rose by 33.2% year-on-year. The main drivers were:

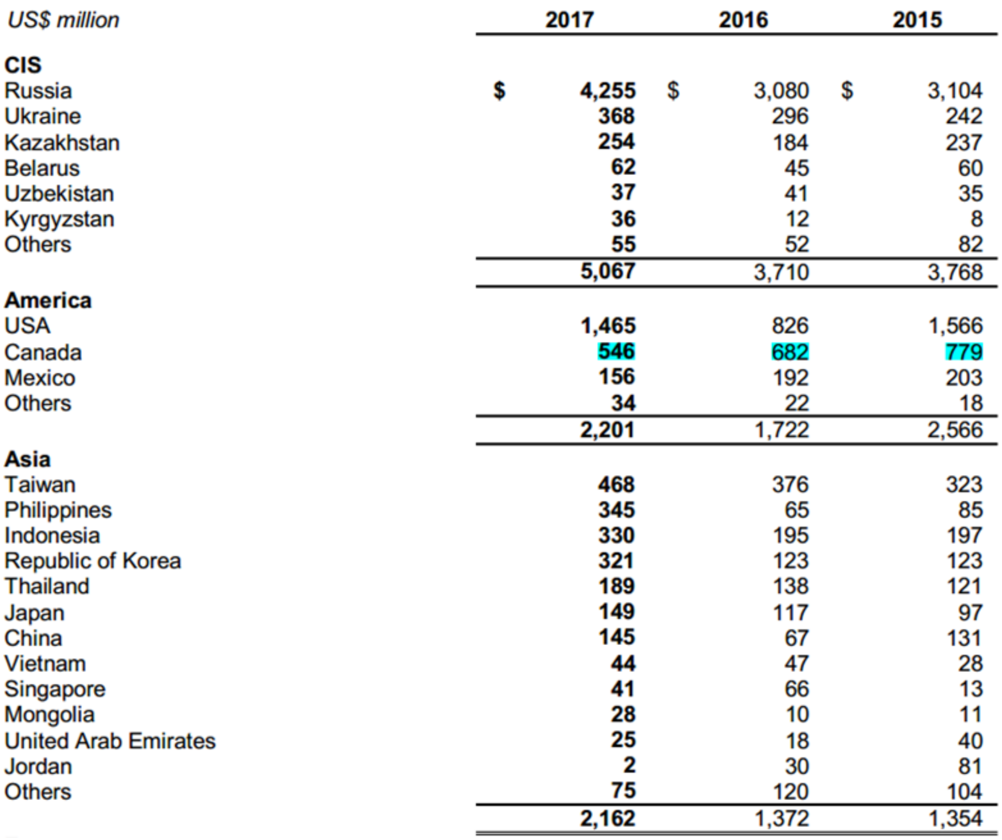
- Raw material costs increased by 65.0%, primarily because of higher scrap prices, accompanied by increased consumption of other raw materials due to higher sales of tubular products driven by the market recovery in the reporting period.
- Costs of semi-finished products grew by 61.2% due to higher prices for purchased semi-finished products and increased sales volumes of steel products.
- Auxiliary material costs increased by 42.3%, as production volumes of crude steel and finished products were higher year-on-year.
- Service costs went up 14.8%, as sales volumes increased year-on-year.
- Energy costs grew due to higher rates and greater sales volumes of steel products.
- Other costs were down for the reporting period, primarily due to changes in work in progress and finished goods and allowances for inventories.

Table 37. Steel North America segments cost of revenue and distribution of the Group's revenues by geographical area



Steel North America segment cost of revenue

	2017		2016		
	US$ million	% of segment revenue	US$ million	% of segment revenue	Change, %
Cost of revenue	**1,656**	**88.8**	**1,243**	**84.9**	**33.2**
Raw materials	645	34.6	391	26.7	65.0
Semi-finished products	303	16.3	188	12.8	61.2
Auxiliary materials	148	7.9	104	7.1	42.3
Services	124	6.7	108	7.4	14.8
Staff costs	254	13.6	195	13.3	30.3
Depreciation	95	5.1	97	6.6	(2.1)
Energy	111	6.0	85	5.8	30.6
Other*	(24)	(1.4)	75	5.2	(n/a



US$ million	2017	2016	2015
CIS			
Russia	$ **4,255**	$ 3,080	$ 3,104
Ukraine	**368**	296	242
Kazakhstan	**254**	184	237
Belarus	**62**	45	60
Uzbekistan	**37**	41	35
Kyrgyzstan	**36**	12	8
Others	**55**	52	82
	5,067	3,710	3,768
America			
USA	**1,465**	826	1,566
Canada	**546**	682	779
Mexico	**156**	192	203
Others	**34**	22	18
	2,201	1,722	2,566
Asia			
Taiwan	**468**	376	323
Philippines	**345**	65	85
Indonesia	**330**	195	197
Republic of Korea	**321**	123	123
Thailand	**189**	138	121
Japan	**149**	117	97
China	**145**	67	131
Vietnam	**44**	47	28
Singapore	**41**	66	13
Mongolia	**28**	10	11
United Arab Emirates	**25**	18	40
Jordan	**2**	30	81
Others	**75**	120	104
	2,162	1,372	1,354

The Steel, North America segment's gross profit totalled US$208 million for 2017, down from US$221 million a year earlier. While the decline was primarily caused by higher prices for scrap and purchased semi-finished products, it was partially offset by an increase in revenues due to improved market conditions.

In Appendix 2, the unrealized profits or losses that relate to the inventories produced by the Steel, North America segment's balance sheet in 2016 and 2015 can be found accordingly.

The following Table 38 summarizes the distribution of the group's revenues by geographical area based on the location of customers for the years ended 31 December. We use the output ratio in Canada region to estimate the revenue in EVRAZ Regina.

We know the total emissions in EVRAZ Regina is 216750, 210654 and 165648 tonnes in 2015, 2016 and 2017 separately. From tables above, we use the output ratio in Canada region to estimate the revenue and benefit in EVRAZ Regina. It may be higher than the actual revenue and net benefit since we do not know their interests and taxes. In this case, the total benefit will be 115 million, 113 million and 66.6 million in 2015, 2016 and 2017. The total output will be 890 million, 749 million and 616 million in 2015, 2016 and 2017.

$$\text{Affordable Penalty} = \text{Total benefit} / \text{Total emissions}$$

The emission penalty under different carbon tax scenarios are listed in Table 35. The carbon levy rate range from 10 C$/tonne to 50 C$/tonne of carbon emission released by the coal mining process. Total benefit is the mean of three years. Penalties are calculated under different scenarios.

$$\text{Penalty} = \text{Carbon levy tax rate} \times \text{Total emission}$$

$$\text{Net Benefit} = \text{Total benefit} - \text{Penalty}$$

3.8. Affordable penalty analysis of Terra Grain Fuels Inc.

Table 38 Affordable penalty summary of Terra Grain Fuels Inc.

Year	Total Output (million C$)	Total Benefit (million C$)	Total Emissions (tonne)
2013	129.59	54.59	75092
2014	122.86	47.86	67141
2015	85.09	10.09	73879

Table 39. Emission penalty under different scenarios of Terra Grain Fuels Inc.

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	10.09	73879	0.73	7.2%
20 C$/tonne	10.09	73879	1.46	14.5%
30 C$/tonne	10.09	73879	2.19	21.7%
40 C$/tonne	10.09	73879	2.92	28.9%
50 C$/tonne	10.09	73879	3.65	36.2%

Note: Data of 2015 is taken as an example.

3.8.1 Introduction of The Terra Grain Fuels

When most people think of ethanol they think of corn. However up in Saskatchewan wheat is being tapped to produce the biofuel, and has gotten a big boost with the opening of a new biorefinery. The Terra Grain Fuels ethanol plant is located in the Rural Municipality of Pense No.160, near Belle Plaine, Saskatchewan and is a completely owned company with a local group of private investors.

Construction on the plant began in 2006. Terra Grain Fuels began producing and shipping ethanol in the summer of 2008. This facility is run twenty-four hours a day, seven days a week by a central control system and features leading edge technologies from around the world. This includes a state of the art lab with world class quality control on all of the biofuel products produced.

Terra Grain Fuels purchases approximately 15 million bushels or 400,000 MT of wheat from farmers within a radius of 160 kilometres of the plant every year. The plant is currently running at about 60% of the design capacity due to limitations in milling capacity. At full capacity, the plant will purchase and consume over 15 million bushels of locally grown wheat per year, and through the fermentation process will transform the starch embedded in the wheat into ethanol, a clean - burning, renewable fuel often blended with gasoline. The plant produces 150 million litres of ethanol and 160,000 tonnes of dried distillers grains annually.

The company’s commitment to using locally grown wheat will assist in attaining a profitable and sustainable Saskatchewan wheat market, providing producers with greater flexibility for the future. Figure 10 is the partial site plan.

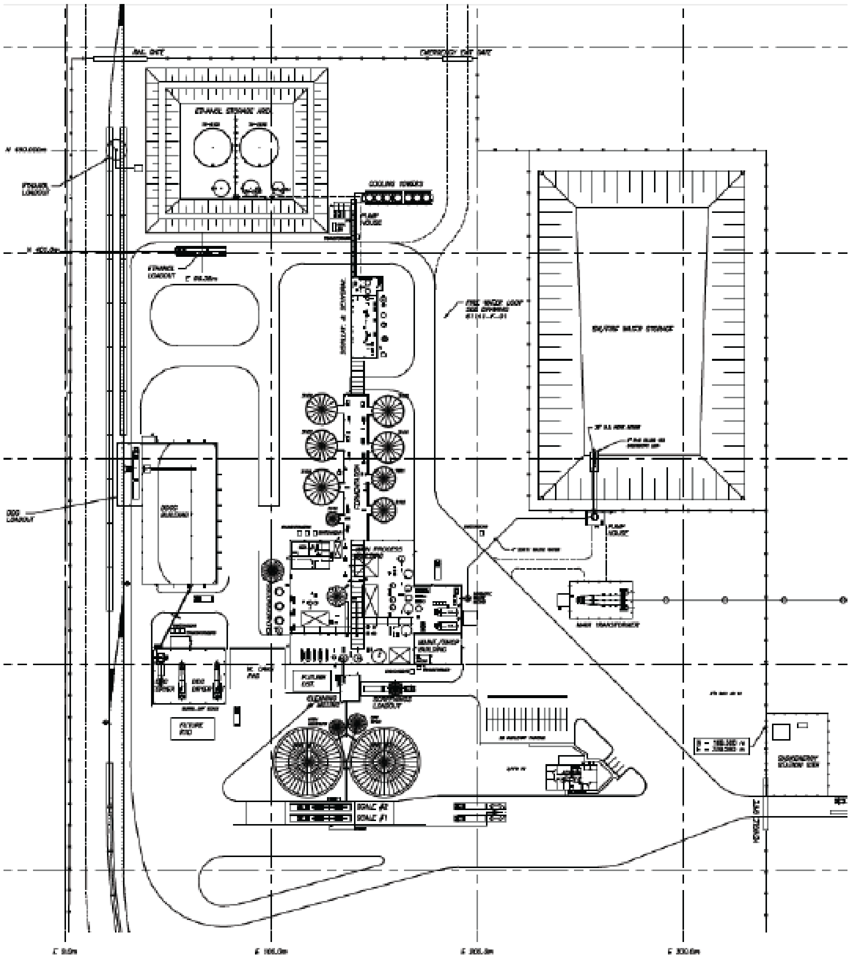


Figure 10. Partial site plan

History

Terra Grain Fuels is the largest wheat based ethanol producer in the province of Saskatchewan. Construction of the plant began in June 2006, and was ready for testing by July 2008. During this time, the site was prepared, the approvals were secured, the equipment was ordered, and the site and facility was constructed for an Ethanol Production plant designed by Delta-T Corporation with a design capacity of 150 million litres of ethanol annually. The first load of feedstock for non-testing purposes was milled in August 2008. On March of 2010, the facility underwent a milling upgrade to replace roller mills with hammer mills thereby increasing plant capacity. A scheduled maintenance program is carried out every 6 months during which the facility is hydro blasted.

The Project meets the requirements of the GHG CleanProjectsTM registry, including conformance with ISO 14064 Part 2: Greenhouse Gases: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements (ISO 14062-2). The Project also meets the eligibility requirements as specified in the Protocol, used as guidance for this Project.

Table 40. Emissions reduction eligibility claim

Start Date	Based on the Alberta regulations, only projects initiated after January 1, 2002 are eligible to generate Emissions Reductions. This project was commissioned in mid-2008. The first load of grain for non testing purposes was milled on August 28th 2008. This date is used as the official project start date.
Claim Period	The Project proponent intends to claim Emissions Reduction reductions for an initial period of 8 years, as specified in the Guidance Document. The end of the initial Project Emissions Reduction crediting period is thus set at August 31st 2016. Since Saskatchewan's offset market is not regulated, TGF may provide justification for prolonging this crediting period.
Real, Demonstrable and Quantifiable	The Project is real, demonstrable, and quantifiable since it causes a net reduction of greenhouse gases involved in the project and since the methodologies outlined in this Project Report are in accordance with the Biofuel Protocol and are based on measured and documented activities.
Surplus to Regulation	While a federal renewable fuel standard will be in place in 2010 requiring all gasoline sold in Canada to include 5% ethanol, TGF has been at no point mandated by the Government of Canada to produce ethanol. Provincial standards in Ontario have required 5% since 2007, 7.5% in Saskatchewan since 2005, 5% in B.C. in 2010, and 5% in Alberta by 2010. These standards however, have not required the facility to produce ethanol. Secondly, under the eco-Energy for Biofuels program of the Department of Natural Resources, TGF receives approximately 10 cents per litre of all ethanol produced. While this is an incentive program, TGF has not been mandated to produce ethanol, nor does the payment represent a major component of the production costs.
Ownership	All Emission Reductions generated by the Project are owned solely by TGF. They are responsible for the production of the ethanol. Further, they are the only party with access to the production information required to quantify the reductions. None of the sales contracts between TGF and the buyers (Elbow River Marketing L.P., Petro Canada, Shell Trading Canada, Imperial Oil Limited, and Consumer's Cooperative Refineries Limited) transfer the environmental attributes to the gasoline blenders. Starting in December 2009, a clause has been added to the ethanol purchase agreements which clearly assert that TGF retains ownership of the Emission Reductions associated with the ethanol to eliminate any possible ambiguity.
Location	According to AESRD, to satisfy this condition feed stock must originate from within Canada, and the ethanol must be produced in Saskatchewan. Any feedstock purchased from outside of Canada is subtracted from the ethanol produced and not included in volume of ethanol produced under the project condition. All other grain is demonstrated to have been produced in Canada through grain receipts. The project site description clearly shows the project boundaries to be within the Province of Saskatchewan.

Feedstock Sourced in Canada

TGF is uniquely configured to only use wheat as a feedstock. Wheat is purchased exclusively from Canada. In Saskatchewan, where most of the wheat is sourced, approximately 400 farmers are on forward contracts with TGF. Less than 1% of their grain has been sourced from Manitoba. At no time in the past, has TGF sourced grain from the United States, or any other country outside of Canada. If at any time in the future, non-US grain was included as feedstock, the ethanol produced would be subtracted from the GHG Emission Reduction assertion. Between 20,000 and 25,000 metric tonnes of wheat is delivered monthly, but this will increase in 2010 with the expansion of milling capacity. The main variety used is AC Andrews, which is a soft white spring wheat, but the plant has also accepted hard and soft red wheat, durum, tarmigan, and Canadian spring white wheat on occasion.

Product

(1) Ethanol:Terra Grain Fuel sells ethanol to blenders in Saskatchewan, Alberta and Manitoba. The ethanol sold is typically blended into petroleum gasolines. Because ethanol is constantly being produced, we are able to provide a steady supply of ethanol to blenders on a monthly and weekly basis. Terra Grain Fuels also participates in the Blenders Credit program administered by the Government of Saskatchewan.

(2) Dried distillers grains: Terra Grain Fuels produces 160,000 tonnes of dried distillers grains (DDGs) annually. DDG is a byproduct left over after the grains have been processed which consists of the bran and fibre that are left over once the starches have been taken out of the kernel. Terra Grain Fuels then puts this byproduct through a dryer and stores it or ships it to feed lots and plants.

This is an excellent feed product and compliments silage and poor hay crops well as its high in protein with a level of approximately 34 to 35 percent. Thirty-six percent of the grain taken in for ethanol processing is returned to the feed market annually. Terra Grain Fuels participates in research with the University of Saskatchewan to ensure the highest quality of dried distillers grains is being produced.

Purpose

Terra Grain Fuels provides additional economic marketing choices to local wheat producers for non-food grade wheat. The wheat is converted in to ethanol which supplies the government mandated demand for ethanol in retail gasoline in Western Canada.

Vision

To efficiently produce environmentally friendly renewable fuel to supply western Canadian government mandated demand. We will be dependable business partners with our customers and suppliers

Differentiation

Terra Grain Fuels uses predominantly wheat as its feedstock. Wheat ethanol has a lower carbon intensity than corn ethanol. Therefore ethanol produced from wheat has lower life cycle carbon emissions than the majority of the ethanol produced in North America. Wheat dried distillers grains also has the advantage of higher protein levels than corn dried distillers grains and garners a premium price.

Legacy

Terra Grains contributes to the local economy by providing skilled jobs and an alternate grain marketing choice to farmers for a historically difficult agricultural commodity to market. The annual economic footprint to the local economy is in excess of $100 million dollars. TGF helps the environment by producing renewable clean burning ethanol which reduces greenhouse gas emissions over standard fossil fuels.

3.8.2 Process flow of the ethanol plant

The TGF plant is a dry mill operation that processes wheat as the feedstock. Figure 11 shows the Process of the Ethanol Plant. A brief description of each stage of the process is as follows:

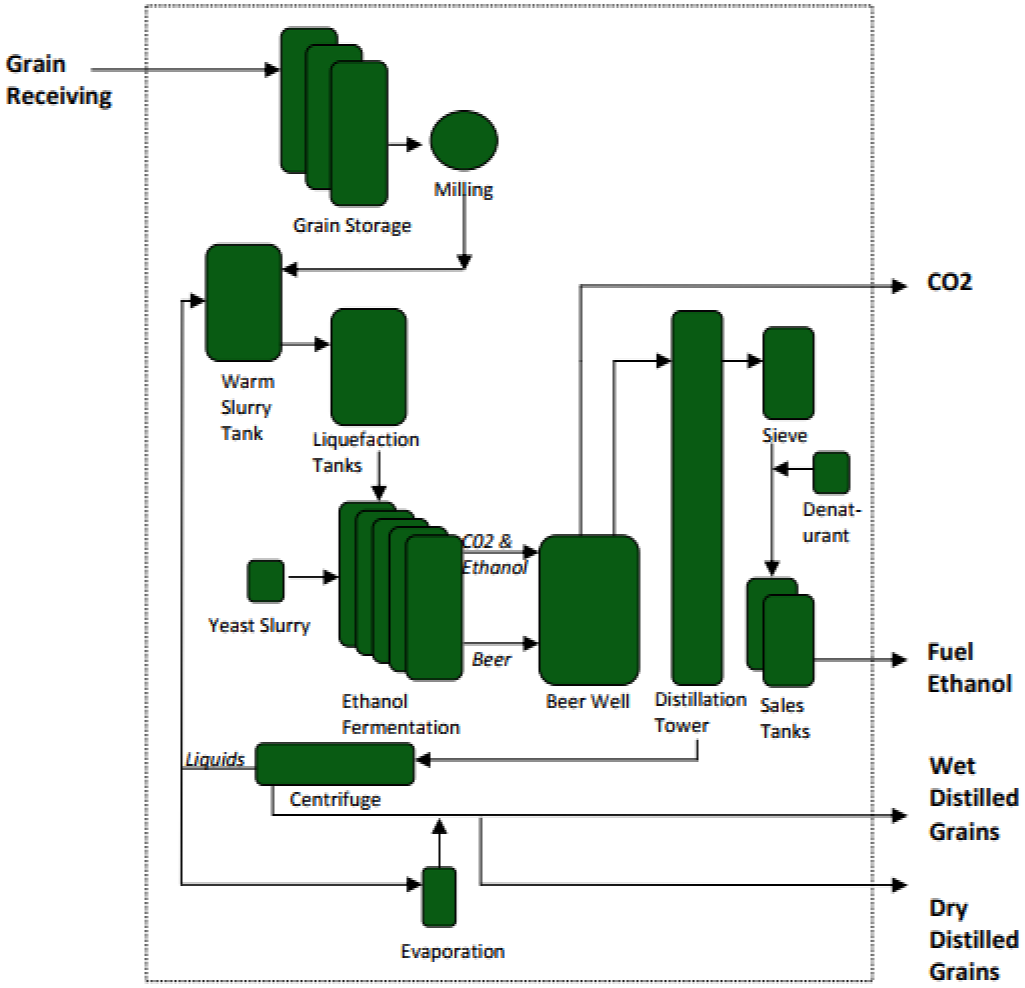


Figure 11. Ethanol plant process diagram

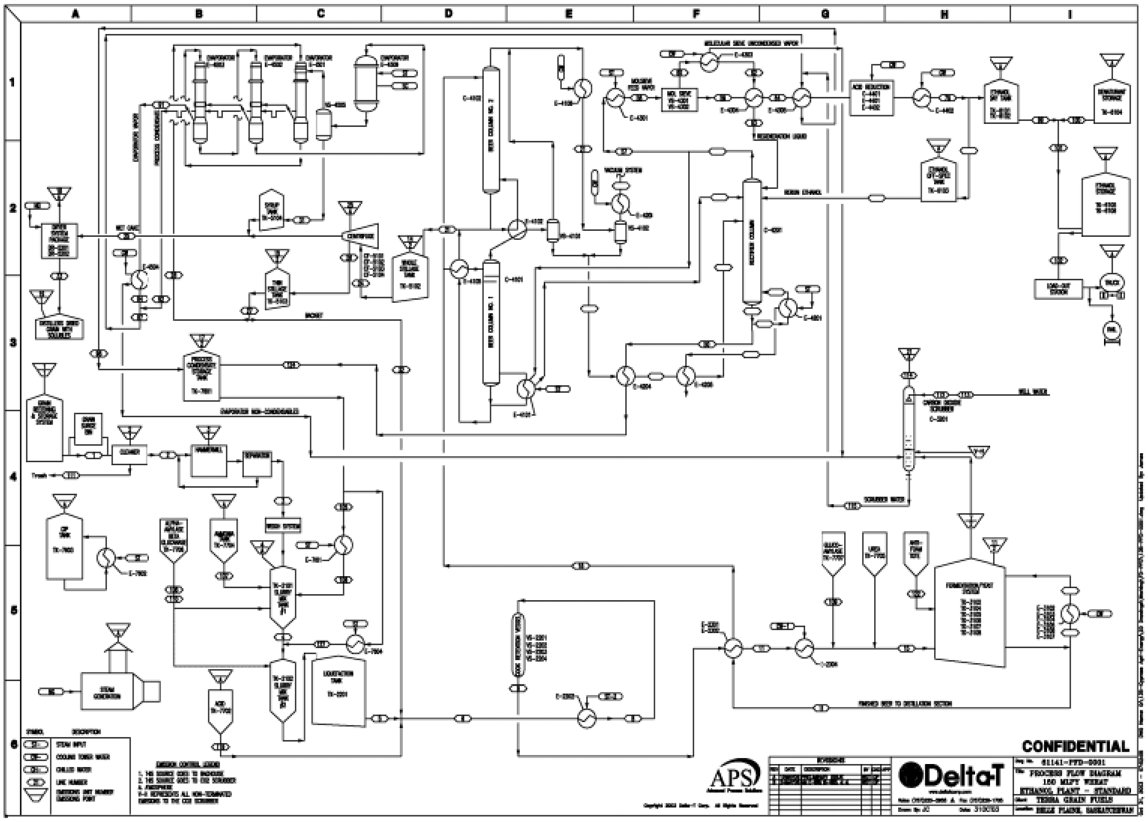


Figure 12. Full process diagram

(1) Grain Unloading: Trucks deliver the wheat directly from the farm or from elevators. There is no option to accept rail delivery of grain.
(2) Milling: The wheat first passes through a proprietary grain milling system which mills the wheat into a fine powder called meal. This area has a cyclone dust collector system designed to eliminate grain dust during milling.
(3) Liquefaction: The meal is then mixed with water and the enzyme alphaamylase and passes through cookers, where the starch is liquefied. Heat is supplied at this stage to enable liquefaction
(4) Saccharification: The mash from the cookers is cooled and the secondary enzyme, gluco-amylase, is added to convert the liquefied starch to fermentable sugars, a process called "Saccharification."
(5) Fermentation: Yeast is added to the mash to ferment the sugars to ethanol and biogenic carbon dioxide.
(6) Distillation: The fermented mash, now called "beer", contains about 12.5% ethanol by mass as well as the non-fermented solids from the wheat and the yeast cells. The beer mash is pumped to a continuous flow, multi-column distillation system where the ethanol is separated from the solids and water. The ethanol leaves the top of the final column at approximately 95% strength and the residual mash, called stillage, is recovered from the base of the column and transferred to the by-product processing area.
(7) Dehydration: The ethanol from the top of the column passes through a dehydration system where the remaining water is removed. The alcohol product at this stage is called anhydrous ethanol and meets the requirements of the CGSB for fuel ethanol.

(8) By-Product Recovery: Evaporators and gas fired ring dryers are used to remove the water from the stillage and produce the DDG.
(9) Ethanol Storage: The ethanol is stored in carbon steel tanks and the tanks are sized to contain 15 days of production storage. Additionally, and as regulatory requirements dictate, the ethanol is blended on site with a 1 to 5 percent mix of gasoline.
(10) Ethanol and DDG Loadout: Trucks and railcars will move the ethanol to the gasoline terminals. Likewise, trucks and railcars will be used to deliver the DDG to the ultimate customers.

In the first year of operation the plant produced an average of 155,000 litres of ethanol monthly. This ethanol is sold to petroleum retailers in Saskatchewan, Alberta, Ontario and British Columbia, who blend the ethanol with their gasoline product. As a co-product the plant is expected to produce 163,800 tonnes of dried distillers grains annually- a product that is marketed as high protein animal feed.

3.8.3. Plant Emission Sources

Each Emission Source has been described as follows.

Table 41. plant emission sources

Source	Description
Facility Operation	Greenhouse gas emissions may occur that are associated with the operation and maintenance of the project site. This may require any number of mechanical, chemical or biological processes including those related to processing inputs and generating outputs (including those other than the biofuel) for downstream use. All relevant characteristics of the material inputs would need to be tracked to prove functional equivalence with the baseline scenario.
Biofuel Production	This SS encompasses the process emissions for the biofuel production. This may results from chemical, biological and mechanical processes used in the production of biofuel. All relevant characteristics of these processes would need to be tracked.
Biochemical Production	Biochemical feedstocks may be generated that would serve to Emissions Reduction petrochemical feedstocks. This may result from chemical, biological and mechanical processes used in the production of the biochemicals. All relevant characteristics of these processes would need to be tracked.
Electricity Production	Electricity may be generated to meet internal project demand or for export from the project site. The generation of this electricity may yield incremental greenhouse gas emissions. Quantities and types for each of the energy inputs would be tracked.
Generation of Heat and Power	The generation of heat and power may occur at the project site for sale to other facilities. This generation could require the combustion of fossil fuels precipitating greenhouse gas emissions. Volumes and types of fuels are the important characteristics to be tracked.

3.8.4 Affordable penalty analysis

According to The Terra Grain Fuels 's annual production of 150 million litres of ethanol and 160,000 tonnes of dried distillers grains, it is easy to estimate total output based on the annual commodity unit price. As annual unit price is affected by various factors, the total output value fluctuates within a certain range. TGF is uniquely configured to only use wheat as a feedstock. Wheat is purchased exclusively from Canada. In Saskatchewan, where most of the wheat is sourced, approximately 400 farmers are on forward contracts with TGF. So Terra Grain Fuels purchases approximately 15 million bushels or 400,000 MT of wheat from farmers within a radius of 160 kilometers of the plant every year. The Terra Grain Fuels will formulate corresponding prices for various wheat varieties to buy wheat from different farms. The cost of purchasing raw materials is tentatively set as the total cost (due to the lack of cost data on the company's energy use and labor input, the accuracy of the data needs to be improved.).

As shown in the table, the total output values for 2013, 2014, 2015 are 129.6 million, 122.9million and 85.1 million C$ respectively, and the annual profits are 54.6 million, 47.9 million. 4 and 10.1 million C$ respectively. There are also three years in the company's emissions data. Based on this data, we can calculate the carbon tax price that the company can afford. From the table, it can be seen that in the year of 2013, 2014, 2015, due to the difference in the annual operating conditions, there is a difference in the ability to pay carbon tax. Carbon tax payable in 2013 years is 727 C$. It is the year that the affordable carbon tax is the highest in three years.

In table 39 based on the data of year 2015, We calculate the company’s penalty as well as net benefit under different carbon tax scenarios as listed in Table 39. It can be seen that the price of carbon tax can directly affect the profits of the company, and even affect the company's operating conditions. If the carbon tax is too low, the penalties for the emission companies will not be obvious. Competent companies may even ignore the carbon tax directly. It did not play a due role in reducing emissions. If the carbon tax is too high, some companies will reduce production on the original basis in order to achieve the goal of emission reduction. This will not only reduce the company's profit margins, but will even cause some companies to face bankruptcy.

In total, Terra Grain Fuels is the largest wheat-based ethanol producer in the province of Saskatchewan, its carbon emissions cannot be ignored. It cannot blindly pursue economic interests and ignore environmental conditions. However, the formulation of a carbon tax is determined based on the actual operating conditions of each company. The aforementioned carbon tax scenarios have already reflected the company's economic status under different carbon taxes. Finally, a unified carbon tax standard of this industry should be established based on the actual situation of all companies in Saskatchewan.

3.9. Affordable penalty analysis of Meadow Lake Mechanical Pulp Inc.

Table 42. Affordable penalty summary of Meadow Lake Mechanical Pulp Inc.

Year	Total Output (million C$)	Total Benefit (million C$)	Total Emissions (tonne)
2013	270.91	12.77	74780
2014	298.19	27.22	76244
2015	298.01	27.04	79052

Table 43. Emission penalty under different scenarios of Meadow Lake Mechanical Pulp Inc.

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	27.04	79052	0.79	2.9%
20 C$/tonne	27.04	79052	1.58	5.8%
30 C$/tonne	27.04	79052	2.37	8.8%
40 C$/tonne	27.04	79052	3.16	11.7%
50 C$/tonne	27.04	79052	3.95	14.6%

Table 42 shows the affordable penalty summary of Meadow Lake Mechanical Pulp Inc. The total output of Meadow Lake Mechanical Pulp Inc.in 2013, 2014, and 2015 is 270.9, 298.2 and 298.0 million C$ respectively. The total benefit of the company in 2013, 2014, and 2015 is 12.8, 27.2 and 27.0 million C$ respectively. The total emissions of the company in 2013, 2014 and 2015 are 74,780, 76,244 and 79,052 tonnes respectively. Following this, affordable penalty is equal to total benefit divided by total emissions. Therefore, the affordable penalty of the company in 2013, 2014, and 2015 is 170.76, 357.00 and 342.09 C$/tonne respectively. Because financial and other related data of Meadow Lake Mechanical Pulp Inc. are not available, the data in the Table 42 are calculated by the data of a similar company: Canfor Pulp Inc. The company of Canfor Pulp will be introduced in 3.10.2.

Table 43 shows the emission penalty under different scenarios of Meadow Lake Mechanical Pulp Inc. Under the different carbon tax rate scenarios, based on the data of 2015, penalty can be calculated. Penalty is equal to total emission multiplied by carbon tax rate. So net benefit is equal to total benefit minus Penalty. As shown in Table 43, when the carbon tax rate is 10 C$/tonne, penalty is equal to 790,520 C$, so net benefit is equal to 26,252,622 C$; when the carbon tax rate is 20 C$/tonne, penalty is equal to 1,581,040 C$, and net benefit is equal to 25,462,102 C$; when the carbon tax rate is 30 C$/tonne, penalty is equal to 2,371,560 C$, and net benefit is equal to 24,671,582 C$; when the carbon tax rate is 40 C$/tonne, penalty is equal to 3,162,080 C$, and net benefit is equal to 223,881,062 C$; when the carbon tax rate is 50 C$/tonne, penalty is equal to 3,952,600 C$, so net benefit is equal to 23,090,542 C$.

3.9.1. Company profile

Situated in North West Saskatchewan, Canada, Meadow Lake Mechanical Pulp Inc. which is part of the Paper Excellence Group, produces pulp using a Bleached Chemi-thermal-Mechanical Pulp (BCTMP) process, which employ heat, mechanical action and mild chemicals to separate cellulose fibers. The process produces pulp valued for its bulk, opacity and stiffness. These attributes make it highly suitable for fine printing and writing papers, tissue and toweling, paperboard and specialty papers. MLMP has the distinction of being the world's first successful zero-liquid effluent-discharge market pulp mill.

The US$350 million Millar Western Meadow Lake Mill is located on a 247-acre (1 km2) site about 200 miles (322 km) northwest of Saskatoon, Saskatchewan. It uses mechanical action supplemented by mild chemicals to turn aspen wood chips into bleached chemi-thermo-mechanical pulp (BCTMP), about 240,000 metric tons per year. More efficient than the kraft process, this approach uses half the trees to make the same amount of pulp, producing almost one ton of pulp for each ton of wood on a water-free basis. The Millar Western BCTMP process also eliminates chlorine compounds and odorous sulfur-based impregnation chemicals. This environmentally-friendly mill uses hydrogen peroxide to increase the brightness of the pulp, making it suitable for printing and writing grades of paper as well as for tissue and paper towels.

Sustainability Environmental Policy (ISO 14001:2004 certified): Meadow Lake Mechanical Pulp Inc. is the world's first successful zero-liquid effluent pulp mill. We produce totally chlorine-free, high yield mechanical pulp. Our goal is to enhance our position as an internationally competitive and sustainable business while minimizing any impact on the environment.

It is committed to meet the requirements of all applicable environmental laws, regulations, standards, and voluntary programs; Continuously improving our management systems, technologies and processes to identify environmental aspects and to minimize their impacts with respect to air emissions, accidental discharge, waste management and resource consumption; Setting measurable objectives and maintaining reliable processes for tracking our environmental performance; Maintaining open communication with our employees, the public, our customers and regulators.

Quality Policy (ISO 9001:2008 Certified): Meadow Lake Mechanical Pulp Inc. is to enhance our position as an internationally competitive and sustainable market pulp mill by providing consistent quality pulp that meets the requirements of the customers. Meet applicable legislation, certifications, industry standards, and other requirements including those of customers. Ensure pulp meets customer quality specifications. Ensure the documentation, packaging, transportation and delivery of our pulp meets customer requirements. Produce pulp in an efficient, cost-competitive manner, and use resources effectively. Continually improve the effectiveness of the management system and processes. Resolve all customer inquiries or concerns. Maintaining high expectations for product and process performance is an integral part of the business.

3.9.2. Introduction of the comparison company - Canfor Pulp Inc.

Because financial and other related data of Meadow Lake Mechanical Pulp Inc. are not available, the data in the Table 43 are calculated by the data of a similar company: Canfor Pulp Inc.

Canfor is a leading global supplier of pulp and paper products, with four mills in British Columbia – three in Prince George and one in Taylor. British Columbia’s northern forests produce some of the finest trees and fibre available for pulp and paper. The climate encourages slow growth of white spruce, lodgepole pine and alpine fir trees that produce long, slender, flexible and strong cellulose fibres. Our pulp is known for its superior strength and quality, and it is continuously improving our environmental and operational performance. Most of its production is northern bleached softwood kraft (NBSK) pulp but it also produces specialty unbleached and bleached chemo-thermo mechanical pulp. Our pulp mills are true bio-refineries – it produce quality pulp and paper products and it generates green energy for our own operations and for sale to consumers, minimizing waste and ecological impact.

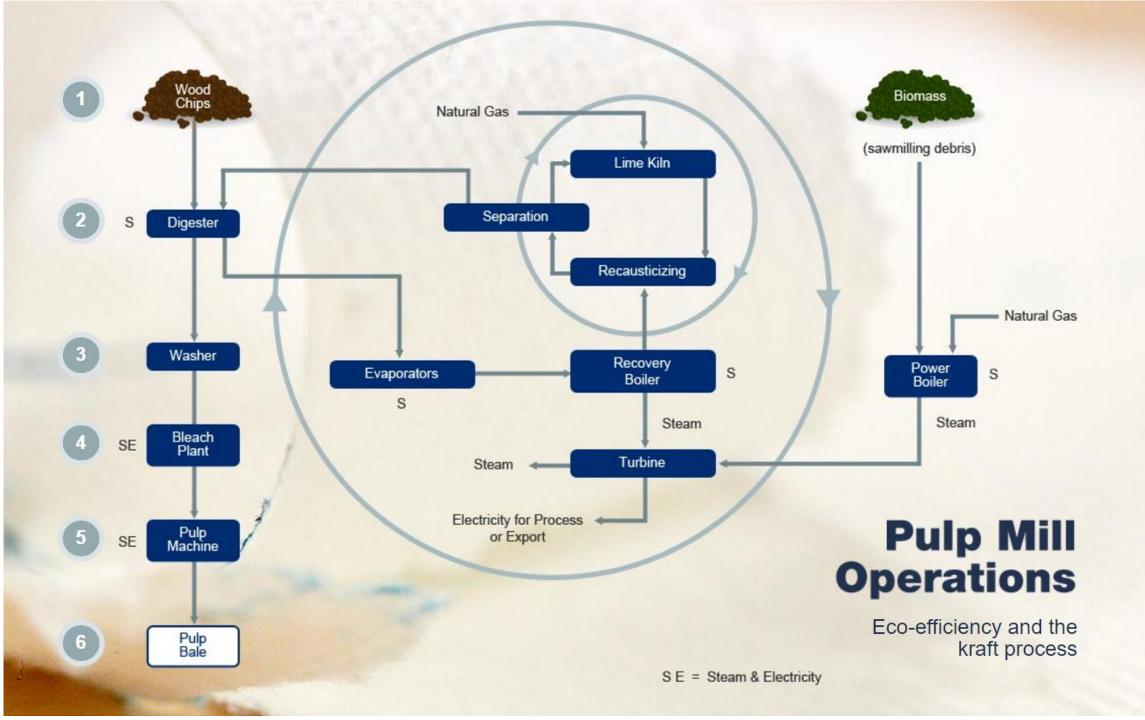


Figure 13. Operations of Canfor Pulp

Canfor use virtually 100% of the wood fibre to create useful products. The residuals from the lumber operations become a source of fibre for the pulp mills, are used to heat the sawmills or are turned into pellets that are exported as a green fuel source. Canfor Pulp is one of the largest single producers of bioenergy in North America. The modern kraft pulp mills operate as a large-scale bio-refinery, and Canfor is near to reaching the goal of becoming energy self-sufficient and exporting surplus power to the electricity grid. Canfor generate over 910,000 MW/h of electricity a year – enough to power a city the size of Prince George.

Canfor continue to pursue a number of projects that will improve the environmental performance and/or energy efficiency of the pulp mills. Canfor reduced fossil fuel use by 70% in the last 15 years so greenhouse gas emissions are at an all-time low. Since 2012, Canfor have realized substantial benefits from capital investments, including more renewable energy, lower heat losses and fewer emissions. The processes are more eco-efficient, and the goal is to develop enough capacity to become energy self-sufficient. The pulp mills separate fibres and use the non-fibrous components as fuel, minimizing waste and the ecological impact. Canfor use steam generated in the boilers to generate electricity and heat for the operations, and we export surplus power to the grid for other users. The recovery and utilization of the black liquor produced in the pulping process is an essential part of the pulp production process. Half of the wood raw material is utilized as chemical pulp fiber. The other half is utilized as fuel for electricity and heat generation.

The thermal heat energy systems use bark and, in some cases, planer shavings to dry lumber and heat the mills. By creating energy from manufacturing by-products, Canfor reduce or eliminate the reliance on natural gas, decrease the greenhouse gas emissions, improve air quality, reduce the mill conversion costs, and improve wood fibre utilization. Eight of the mills – Fort St John, Mackenzie, Prince George, Plateau, Chetwynd, Vavenby, Radium, and Elko – have been upgraded to improve utilization of wood residuals and reduce the use of natural gas as an energy source. The Green Energy biomass cogeneration facility in Grande Prairie produces 105,000 MWH of renewable electricity and 200,000 GJ of heat for the sawmill, and sells renewable electricity to the Alberta grid.

By converting sawmill residues into sustainable wood pellets Canfor is able to reduce waste and create a green energy source. The industrial grade fuel pellets produced at our pellet facilities provide clean biomass energy to customers in Europe, North America and Asia.

3.9.3. Operational Overview of Meadow Lake Mechanical Pulp Inc.

Meadow Lake Mechanical Pulp produces Bleached Chemi-Thermo Mechanical Pulp (BCTMP) which can be used in a variety of products including printing and writing paper, coated paper, and board grades. Meadow Lake produces a variety of grades dependant on the end use. BCTMP is sought after because of its excellent optical and bulk properties. Meadow Lake has hardwood aspen, softwood spruce, and pine fibre available for producing a wide range of products. The Meadow Lake Pulp Mill is the first successful zero-liquid effluent mill in the world. A step-by-step overview of the process is described below:

Wood room

The Wood room receives 900,000 cubic meters of logs per year. That equates to approximately 21,000 truckloads of logs. A 30 tonnes portal crane handles the tree length logs by feeding them onto the log deck or storing them. The crane has the capacity to store 200,000 cubic meters of logs at a time. The log decks sort and feed the logs into two ring debarkers and two disc chippers. The Wood room processes 3,000 cubic meters or 70 truckloads of logs per day. The chips are fed into storage bins, where the pulp mill then reclaims the chips to process them into pulp.

Main Mill

Once chips have been reclaimed they are separated into two production lines, and move through several stages of steaming, storage, chemical treatment, and mechanical de structuring in preparation for refining. Refining is the important stage that changes wood chips into pulp, and where the properties of freeness and debris are controlled. Most of the remainder of the Main Mill process is dedicated to bleaching, as well as cleaning and washing impurities out of the pulp. Our Mill uses hydrogen peroxide as one of its main bleaching chemicals. The final stage involves drying, weighing, baling, and packaging the final product. It is then stored in the Warehouse or loaded onto trucks. From the Mill Site, a combination of trucking and rail is used to move the pulp to Vancouver. From there, it is loaded to either container or break bulk ocean freighters and exported. MLMP is capable of producing 360,000 tonnes per year.

Steam & Recovery

The S&R department's role is to supply steam and air for internal customers throughout the Mill Site and to process all liquid effluent discharge into reusable water and chemical recovery. Hence the term "Zero-Effluent Liquid Discharge." All liquid effluent (5500 l/m - 6000 l/m) is directed to a Feed Chest or Settling Pond. From there it is clarified, excess fiber is pressed (to remove any liquid) then recompressed and burned in our Incinerator. The liquid is run through a set of Falling Film Evaporators and concentrated up to 30% solids. This liquid is further concentrated via steam assist to the 68% range and used as fuel in our Recovery Boiler. The waste smelt that flows from the Recovery Boiler is put through a Smelt Dissolving process to produce a substance called Green Liquor. The Green Liquor is filtered, oxidized and re-introduced into the Pulping Process as caustic. This is a continuous cycle and no effluent enters our lakes, rivers, or streams.

Technical

Process testing is conducted in the Lab. The results provide operators with information on Process Operations which helps to determine the required chemical addrates to ensure that the Mill is producing the required product grade. These tests provide information on Mill processes and equipment which helps to optimize operations, and troubleshoot throughout the Mill. The Quality Laboratory is where pulp is tested to ensure that it meets the customer specifications. Quality testing consists of tests to determine the pulps' physical and optical properties, such as: Canadian Standard Freeness, Brightness, Breaking Length, Bulk, Debris, and Chemical Oxygen Demand.

An online instrument called the "Pulp Expert" is used for quality testing at several key points in the process to ensure final product quality. This piece of equipment is verified daily by conducting manual physical and optical testing in the Quality Lab. The Analytical Laboratory is responsible for analyzing samples throughout the Mill. These samples can vary from scale found in a pipe or vessel, to an effluent sample from a process stream or a process chemical. These analyses usually include some determination of the organic to inorganic ratio, and/or elemental analysis. The Analytical Lab will also conduct laboratory trials to help determine the effect of a process change before applying the change to the Mill process.

3.9.4. Characteristics and application Bleaching chemical mechanical pulping (BCTMP)

The main varieties in Canada are quesnel, ranger, tembec blue eagle, millerwesten, fibreco. Chinese in recent years due to the white cardboard, newsprint and munken production, demand for BCTMP has been on the increase. At present, the BCTMP production line is also increasing, such as the sun, chenming and huatai are investing in the new BCTMP production line. The main raw materials are coniferous wood, poplar, birch, maple hardwood, and hybrid varieties of hardwood and softwood. BCTMP has high yield and can save wood; it can replace some broad-leaved wood to bleach chemical wood pulp and reduce the cost of paper. BCTMP has quite a lot of high quality properties, such as improving paper forming, reducing the micro holes on the surface of paper, strengthening the combination of fibers, improving the loose thickness of paper, improving the stiffness of paper, improving the compression performance of paper, and stabilizing the size of paper. But BCTMP also has a weakness that is easy to return to yellow, and is not suitable for storing paper for long time.

The application direction of BCTMP

Toilet paper and towel paper: high free and high yield cork BCTMP is used to produce toilet paper and towel paper, which can provide high pine thickness and water absorption. Nell Koons pulp company has developed a unique production process to produce a very high degree of free, low fines, low B C T M extract P. This pulp is used to produce high quality kitchen towel paper. The BCTMP produced by the Canadian pulping company is used to replace the bleached chemical wood pulp and produce toilet paper, thereby reducing the cost.

Cardboard: BCTMP is used in the middle layer of cardboard, providing high pine thickness and stiffness. The BCTMP also provides good sheet forming and appropriate interlayer strength to avoid the stratification problem. Generally speaking cork BCTMP is mainly used to produce high strength and high strength cardboard.

Coated printing paper: some Canada Company bleached the pulp whiteness to 85% ISO using TCF bleaching. For example, the knight's high whiteness BCTMP is very suitable for producing coated printed paper, including low quantity coated paper (LWC). Queensland BCTMP also has been widely used in LWC.

Uncoated printed paper: the high opacity of the mechanical pulp, good sheet forming and sufficient strength are suitable for the production of low - quantity uncoated printed paper. BCTMP is suitable for producing copy paper. The produced copy paper has high pine thickness and stiffness, which is suitable for high speed copier. When using more additives and / or two fibers, BCTMP to produce the copy paper can also maintain a high bulk. For example: the whiteness of 80% ISO River BCTMP card can also be used for the production of cork, uncoated printing and writing paper.

Printed paper containing mechanical pulp: generally speaking, low freeness cork mechanical pulp and poplar cork mixed mechanical pulp can replace some or all grindstone pulp, and produce printed paper containing mechanical pulp. Some of the chemical pulp used to increase the strength may still be added. Under the conditions of different degrees of freedom and whiteness, these pulps can provide stable quality. Si Fraser also developed some special kinds of pulp to meet the needs of different paper machines.

Main technical indexes of common BCTMP

The use of BCTMP, the current is generally based on different freeness and whiteness in different paper, white cardboard, newsprint, munken and grohal. BCTMP is widely used in cardboard, writing culture paper, newsprint and toilet paper.

Attention to Canada's BCTMP application

In the use of any new kind of pulp, the paper factory always carries out the laboratory test first. The BCTMP produced in Canada, all in alkaline conditions (pH=8 ~ 9), is made by air drying, with a moisture content of about 16%. It is necessary to eliminate the potential first, so the proper method of wet solution is to be used, that is, the standardized method of dissolving the mechanical wood pulp. For BCTMP, the conventional beating curve is not suitable, because the reaction of high yield wood pulp fiber to low concentration beating is different from that of low yield chemical wood pulp. It is recommended to ease it in water temperature above 50 ℃. It is suggested to refer to TAPPIom-91, or CPPAC. 8 or northern Europe. In actual production operations, BCTMP has some special requirements to do a simple introduction here:

Pulping: In the hydraulic pulping machine, it is suggested that the pulping concentration is 4% to 8%, the pulping temperature is higher than 50 ℃, and the crushing time is 20 min or more. The pulp in the factory has been slightly alkaline, therefore, pulping process easily, without adding any additives. It is suggested that the intermittent hydraulic pulp be used. If the follow-up section has a high frequency machine, and the production process is more mature, the use of continuous hydraulic pulp can also be used.

Guard beating: If press paper and water absorbent paper and cardboard, generally speaking, BCTMP do not need to beat, use high frequency solution. Because the beating degree of the beating is improved, the strength may be strengthened, but the thickness of the pine will be rapidly reduced. If used for coated paper, especially low-quantity coated paper, a slight beating can be used. We suggest that the manufacturer put forward its own free degree requirements by the supplier to provide the free degree of wood pulp required by the customer. BCTMP best pulps with other pulp.

Screen

When BCTMP is produced, some fiber bundles are inevitably brought in. Therefore, it is recommended to strengthen the screening.

In short, through the BCT Canada Air Drying MP pulping is very easy, coupled with the pump, 100% cork stirring and deflaking processes, the total energy consumption generally required for 100 ~ 150kWh/t, but in some cases, if the pulp is unbleached wood pulp or pulp in the system temperature the lack of time, may use 200 ~ 250kWh/t. BCTMP has been used in many kinds of paper and paperboard. The amount of fiber used depends on the variety and the raw material structure and process equipment of the existing plant.

3.10. Affordable penalty analysis of TransGas

Table 44. Affordable penalty summary of TransGas

Year	Total Output (million C$)	Total Benefit (million C$)	Total Emissions (tonne)
2013	118.85	23.81	542099
2014	126.61	14.85	586377
2015	153.76	30.68	515261

Table 45. Emission penalty under different scenarios of TransGas

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	30.68	515261	5.15	16.8%
20 C$/tonne	30.68	515261	10.3	33.6%
30 C$/tonne	30.68	515261	15.45	50.4%
40 C$/tonne	30.68	515261	20.6	67.1%
50 C$/tonne	30.68	515261	25.75	83.9%

Note: Data of 2015 is taken as an example.

3.10.1 Data resource and calculation method

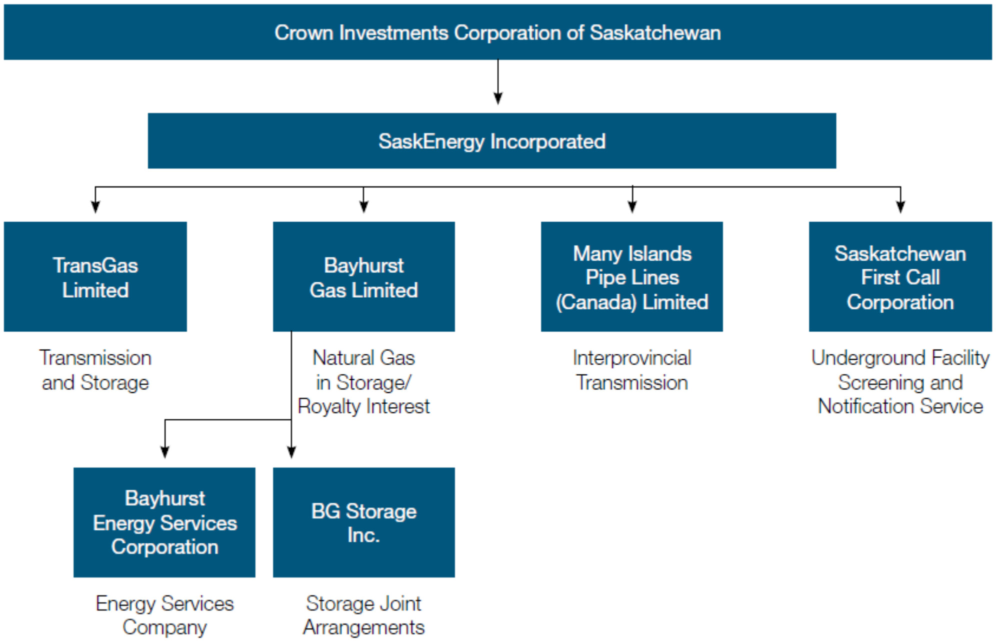


Figure 14. Introduction about SaskEnergy

TransGas is headquartered in Regina, Saskatchewan and its natural gas transmission system covers almost two thirds of the province with a network of more than 14,000 kilometres of high pressure natural gas pipelines. Integral to our system are several strategically located natural gas storage sites with the capacity to provide operational flexibility along with a highly reliable and competitive natural gas storage service.

Situated in the south eastern portion of the Western Canadian Sedimentary Basin, TransGas is ideally situated to serve natural gas producers and consumers. TransGas Limited (TransGas) owns and operates the Transmission Utility and has the exclusive legislated franchise to transport natural gas within the Province of Saskatchewan. It also owns and operates a natural gas storage business as well as gathering facilities, which are integrated with the transmission pipeline system. TransGas and its affiliates own and operate more than 14,000 kilometres of gathering and transmission pipeline as well as several underground natural gas storage sites in Saskatchewan. TransGas has more than 1200 receipt and delivery points on our system to serve our customers which include natural gas producers, commercial entities and industrials within Saskatchewan. Through our numerous interconnects with other pipelines, our system moves Saskatchewan natural gas to markets in eastern Canada and the United States.

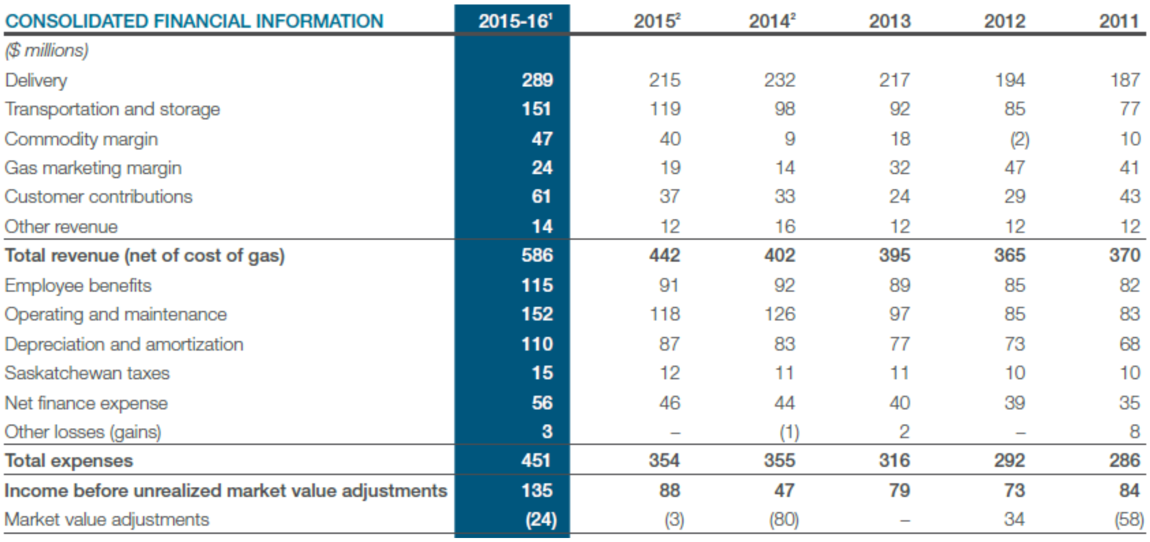
TransGas serves Saskatchewan natural gas producers and end users for almost 60 years. From its early days as part of the Saskatchewan Power Corporation to its present day status as a wholly owned subsidiary of SaskEnergy, TransGas has consistently provided safe, reliable and economical natural gas transportation and storage services. Utilizing a split receipt and delivery transportation model, TransGas provides its customers with a high level of liquidity at our

TransGas Energy Pool ("TEP"), a notional point on its system where producers, marketers and end-users can match supplies to demand.

Although most of their infrastructure is located within the province of Saskatchewan, TransGas is well connected with the major pipelines of western Canada. Through our National Energy Board ("NEB") regulated affiliate, Many Islands Pipe Lines (Canada) Limited ("MIPL") TransGas interconnects with TransCanada Pipelines system in Alberta and with the TransCanada mainline that traverses our province. These interconnects provide the ability for TransGas customers to move gas into Saskatchewan from Alberta as well as to export to eastern markets in Canada.

As shown in Figure 14, TransGas Limited is mainly responsible for the transportation and storage business of SaskEnergy Incorporated. Based on the annual report of SaskEnergy, we are able to calculate the total output and total benefit of the TransGas in 2013, 2014, and 2015. TransGas and its affiliates own and operate more than 14,000 kilometres of gathering and transmission pipeline as well as several underground natural gas storage sites in Saskatchewan. They spent $92 million on system integrity initiatives in 2015, and an additional $15.5 million in the first three months of 2016. They invested in a number of initiatives throughout the year to manage risk and ensure the safe and reliable operation of its distribution and transmission networks, including upgrades to 2,311 gas service connections in Regina, Regina Beach and Rosetown. More than $5 million was spent on mitigation projects throughout the Province, with a focus on Last Mountain Lake and the communities of Regina Beach and Saskatchewan Beach, to increase gas service integrity in communities with possible slope movement.

Table 46. A part of annual report of SaskEnergy



CONSOLIDATED FINANCIAL INFORMATION	2015-16[1]	2015[2]	2014[2]	2013	2012	2011
($ millions)						
Delivery	289	215	232	217	194	187
Transportation and storage	151	119	98	92	85	77
Commodity margin	47	40	9	18	(2)	10
Gas marketing margin	24	19	14	32	47	41
Customer contributions	61	37	33	24	29	43
Other revenue	14	12	16	12	12	12
Total revenue (net of cost of gas)	**586**	**442**	**402**	**395**	**365**	**370**
Employee benefits	115	91	92	89	85	82
Operating and maintenance	152	118	126	97	85	83
Depreciation and amortization	110	87	83	77	73	68
Saskatchewan taxes	15	12	11	11	10	10
Net finance expense	56	46	44	40	39	35
Other losses (gains)	3	–	(1)	2	–	8
Total expenses	**451**	**354**	**355**	**316**	**292**	**286**
Income before unrealized market value adjustments	**135**	**88**	**47**	**79**	**73**	**84**
Market value adjustments	(24)	(3)	(80)	–	34	(58)

The required data can be obtained from the Annual Report of SaskEnergy as shown in Table 46, in which the data of transportation and storage business is detailed. As the main service of the TransGas as a part of the SaskEnergy, data of transportation and storage would be utilized for calculation requirement. From Table 46, we know the revenue of TransGas increased year by year from 2013 to 2015. On November 30, 2015, the Government of Saskatchewan announced a change in the year end for CIC and its subsidiaries from December 31 to March 31, commencing with the 2015-16 fiscal year. Accordingly, for the 2015-16 fiscal year the Corporation reported a

15-month fiscal period ended March 31, 2016. As the data of net income is not included in the annual report and the data of expense is for the SaskEnergy, net benefit need to be calculated according to the existing data. For TransGas, the revenue of 2013, 2014 and 2015 is 118.8 million, 126.6 million, and 153.7 million C$. The proportion of TransGas to SaskEnergy is 23.29%, 24.37%, and 26.92%, respectively. Multiplying the expense of SaskEnergy by the corresponding proportion can lead to the expense of TransGas. Total benefit can be obtained by the following equation,

$$\text{Total benefit} = \text{Total output} - \text{Expense}$$

In table 44, Affordable penalty refer to the fines can be incurred without affecting the normal operation of the company, which could be calculated by the following equation,

$$\text{Affordable penalty} = \text{Total benefit}/\text{Emissions}$$

There are five hypothetical scenarios listed in Table 45, which could provide a basis for setting a reduction policy. The carbon tax rate range from 10 C$/tonne to 50 C$/tonne of carbon emission released by the transportation progress. Taking the year of 2015 as an example, the net benefit with the removal of penalty can be calculated by the following equations,

$$\text{Penalty} = \text{Carbon tax rate} \times \text{Total emission}$$

$$\text{Net Benefit} = \text{Total benefit} - \text{Penalty}$$

Discussing the penalty under different carbon tax rate scenarios can provide a reference for policy makers, which can compensate the losses caused by the development of companies and is also a constraint.

The combination of strategically located storage facilities, extensive pipeline infrastructure, advanced technology and the skilled and dedicated employees all contribute to fulfilling our mission to deliver safe, reliable natural gas solutions that benefit our customers and Saskatchewan.

TransGas is committed to providing safe and reliable service to its customers. Effective customer solutions and responsiveness are also important aspects of the service commitment as evidenced by its Service Excellence mandate. In alignment with Crown Sector Strategic Priorities, TransGas focused on reducing the time it takes to complete new connect requests. Efficient Operations, Safety/Vigilance and Customer Satisfaction make up the three categories of measures against which success is measured related to the Service Excellence mandate. Industry benchmarking and customer surveys provide a valuable gauge against which results can be analyzed.

KAM

The TransGas Key Account Manager (KAM) is a TransGas representative dedicated to represent YOUR needs, finding solutions and bringing the right people together. KAM will assist you with any TransGas related issue, whether your questions are in areas such as contracting, marketing, storage, invoicing, planned outages, or future planning. KAM’s are here to interpret our tariff and business policies as they relate to your particular situation and are here to advocate for the residents. The Key Account Managers, Wendy Uytterhagen and Alyssa Stoeck, each hold a seat at our Customer Dialogue table to propose new ideas and ensure customer needs are met. A Key Account Manager is available daily to discuss the business requirements and on weekends to ensure the transportation and storage needs are met.

Transportation

TransGas offers a variety of transportation services to its customers. Through the use of the TransGas Energy Pool (TEP), TransGas offers receipt and delivery transportation. On the receipt side, TransGas offers both firm transportation and interruptible (best efforts) transportation from points of receipt to TEP.

On the delivery side, TransGas offers firm and interruptible service for gas delivered from TEP to export (interconnecting pipelines), as well as, to the intra-Saskatchewan market.

Storage

TransGas' natural gas underground storage facilities consist of depleted gas fields and solution-mined salt caverns. There are 8 storage locations on the TransGas system providing 49.2 PJ of firm storage capacity. The diverse nature of the storage facilities provides a traditionally reliable storage service. Storage customers can select Firm, Interruptible and Summer Use storage service contracts with terms as short as one month. Customers specify their own combination of storage volume and withdrawal rate, giving them the flexibility to design storage services to meet their unique requirements.

TransGas offers a storage service with flexibility to meet the needs of its end-use natural gas customers, natural gas producers, marketers and aggregators. Although the storage facilities are situated in several locations throughout Saskatchewan, TransGas storage customers are not required to contract at a specific storage site. All TransGas storage customers benefit from the flexibility and reliability that these diversified facilities provide.

TransGas operates several storage locations around the province of Saskatchewan conveniently located to the gas fields, major centres and border points.

TransGas Energy Pool

Working with our customers, in November 1996, TransGas split transportation service into receipt and delivery components, and developed the TransGas Energy Pool (TEP). This way of providing transportation promotes greater commerciality for our customers and creates an active marketplace for natural gas customers in Saskatchewan.

By splitting the transportation service, TransGas allows customers to contract for receipt transportation separately from delivery transportation and hold either or both ends of the transportation service.

Safety is at the core of TransGas's business and, in 2015, the Corporation achieved its best-ever safety performance with a Total Recordable Injury Frequency Rate (TRIR) of 1.86 (injuries per 100 employees). This is down from 2.22 in 2014, which was also a record year. In 2015, TransGas experienced its lowest-ever Preventable Vehicle Collision (PVC) Frequency Rate for the second consecutive year.

In alignment with industry best practices, the Corporation achieved an overall audit score of 94 percent in the Certicate of Recognition (COR) Program, which assesses the elements of TransGas's safety management system against COR Program requirements. Other 2015 safety initiatives included a new employee safety orientation program, which was developed internally to ensure all new and transferred employees receive a consistent introduction to corporate safety practices and procedures.

Damage Prevention Initiatives: As part of its risk and asset management strategy, TransGas engaged in a number of initiatives to reduce damage to its buried infrastructure. As a result, there was a six percent reduction in third-party line hits in 2015, helping to add to a total reduction of nearly 30 per cent since 2013.

The company expanded its Safety Patrol program during the 2015 construction season and added three new patrollers. Originally monitoring neighborhoods in Regina and Saskatoon where Crown utilities have reported higher percentages of facility damages, the program was extended to 16 other communities. The patrollers initiated face-to-face contact with homeowners, local contractors and customers in rental stores and businesses in Regina and Saskatoon to increase awareness of the requirement to contact for line locates before projects got underway. Other initiatives included a new mobile application, supervised crossings, tri-locates, collaborating with SCGA to ensure greater contractor awareness, providing information to businesses that rent digging equipment and public awareness advertising.

At TransGas we take an active role in environmental stewardship through our commitment to environmental leadership.TransGas delivers on its commitment by participating in leading edge construction practices thereby reducing waste and greenhouse gas emissions and improving our air quality. We invest in smart technology and techniques and maintain collaborative partnerships with centres of excellence. We are committed to resource conservation initiatives, habitat enhancement, and we take remedial and restorative measures to reverse any negative impacts of our daily operations. TransGas is committed to the protection of the environment. Commitment to environmental leadership is to reduce the impact of our daily operations on the environment and recognize the role they can play in the stewardship of a non-renewable resource.

The Environmental Management System is a key component to ensure that the company continues to provide safe, reliable and environment-focused service to the customers. Company shall audit its operations and seek feedback from stakeholders to assess its performance. Company shall regard sound environmental management as an integral part of its commitment to the continual improvement of our corporate services and policies, so that service may be provided in an environmentally responsible manner.

This policy applies to the employees and contractors that perform work on behalf of the company. Company will report environmental performance and policy compliance on a regular basis to the Board of Directors, and other stakeholders as appropriate.

As part of its commitment to reducing negative environmental impacts in the Province, the company achieved a number of environmental during 2015. Through the modernization of its compressor the Corporation exceeded its reduction target for compressor emissions by nearly 10 percent. In addition, a record number of projects were reviewed by TransGas's Environment and Sustainability group, the 2015 emissions reduction target was more than doubled through leak repairs and greenhouse gas emissions were reduced by 8,800 tonnes. The Environment and Sustainability group is monitoring regulatory developments pertaining to climate change and air pollutants. While no emissions regulations were implemented, in March 2016 the Federal Government announced commitments toward reducing oil and gas industry methane emissions by 40 to 45 percent over the next decade, using 2012 levels as a benchmark. The company also entered into an agreement with the Ministry of Environment that allows the Corporation to screen and clear certain projects internally in a streamlined fashion relative to the Ministry.

3.11. Affordable penalty analysis of Alliance Pipeline

Table 47. Affordable penalty summary of Alliance Pipeline

Year	Total Output (million C$)	Total Benefit (million C$)	Total Emissions (tonne)
2015	514.90	128.80	388988
2016	519.78	198.20	412109
2017	561.21	228.26	413393

Table 48. Emission penalty under different scenarios of Alliance Pipeline

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	228.26	413393	4.13	1.8%
20 C$/tonne	228.26	413393	8.26	3.6%
30 C$/tonne	228.26	413393	12.39	5.4%
40 C$/tonne	228.26	413393	16.52	7.2%
50 C$/tonne	228.26	413393	20.65	9.0%

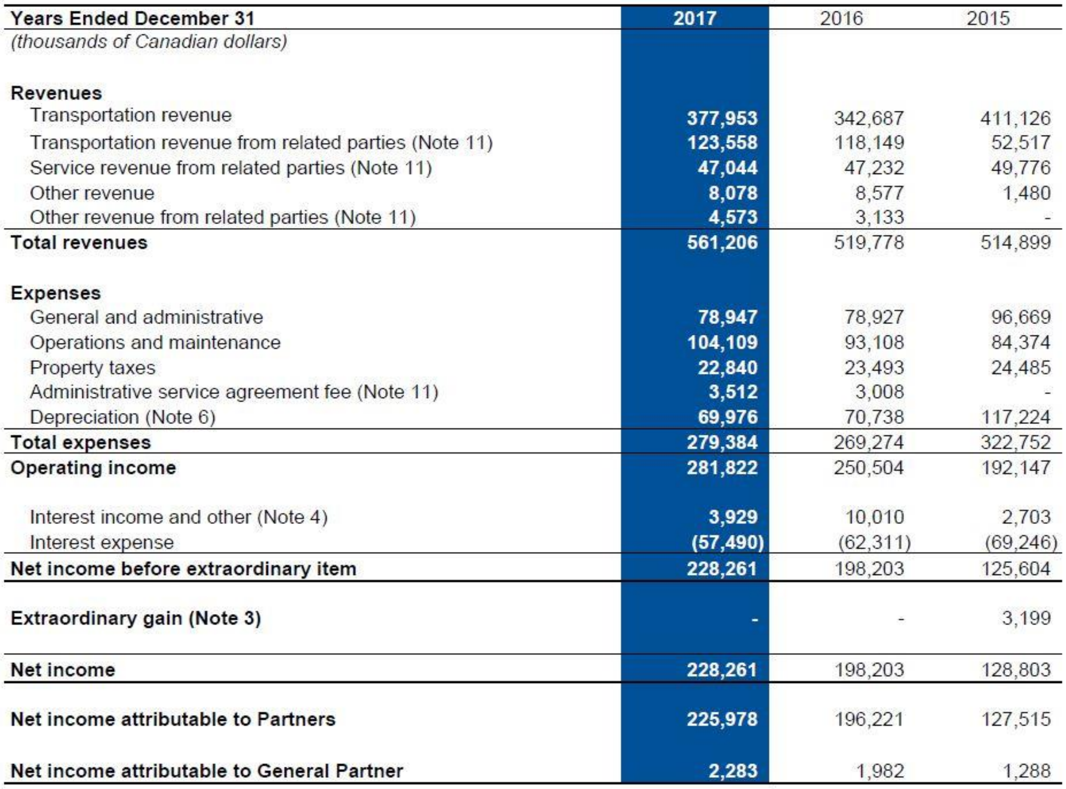
Note: Data of 2017 is taken as an example.

The Alliance Pipeline system consists of a 3,848-kilometre (2,391-mile) integrated Canadian and U.S. natural gas transmission pipeline system, delivering rich natural gas from the Western Canadian Sedimentary Basin and the Williston Basin to the Chicago market hub. The system has been in commercial service since December 2000 and, through an innovative suite of customer-focused services, delivers an average of 1.6 billion standard cubic feet (or 45.3 million standard cubic metres) of natural gas per day. The Alliance Pipeline system transports liquids rich natural gas from northeastern British Columbia, northwestern Alberta and north-central North Dakota, running underground through BC, Alberta, Saskatchewan, North Dakota, Minnesota, Iowa, and terminating in Illinois, the heart of the U.S. Midwest. Alliance delivers approximately 1.6 billion standard cubic feet per day of natural gas to the Chicago market.

In Canada, there are 338 kilometres (km) of 1,067 millimetres (mm) diameter and 1,221 km of 914 mm diameter pipe, 42 receipt points, 7 mainline compressor stations and Maximum Canadian operating pressure: 12,017 kilopascals (kPa).

Pipeline systems are the safest method of transporting hydrocarbon products. Because maintaining the safety and integrity of the relatively new Alliance Pipeline system began during the design phase, the company had an advantage. When Alliance went into service in 2000, it incorporated the numerous advances in pipeline technology and design that had occurred prior to construction of the system. For example, the pipeline walls are 20 to 50 percent thicker than the walls of most other operating pipelines, which helps prevent damage from external forces and reduces the possibility of failure caused by corrosion. Alliance’s wall thickness also enables its ability to ship gas at higher compression. The pipeline is remotely operated and monitored from a central site. The Alliance Pipeline system is very different from its predecessors. Commercially, the Alliance system combines richer gas composition, which is easier to compress, and high-pressure operations. This unique ability to increase compression of the rich gas in pipeline creates a "dense gas", allowing producers to ship more of the energy they produce and to receive greater compensation for their product. Alliance is also an active member on a number of technical committees and industry associations dedicated to continual improvements in pipeline integrity and operations.

Table 49. Annual report of Alliance Pipeline



Years Ended December 31	**2017**	2016	2015
(thousands of Canadian dollars)			
Revenues			
Transportation revenue	**377,953**	342,687	411,126
Transportation revenue from related parties (Note 11)	**123,558**	118,149	52,517
Service revenue from related parties (Note 11)	**47,044**	47,232	49,776
Other revenue	**8,078**	8,577	1,480
Other revenue from related parties (Note 11)	**4,573**	3,133	-
Total revenues	**561,206**	519,778	514,899
Expenses			
General and administrative	**78,947**	78,927	96,669
Operations and maintenance	**104,109**	93,108	84,374
Property taxes	**22,840**	23,493	24,485
Administrative service agreement fee (Note 11)	**3,512**	3,008	-
Depreciation (Note 6)	**69,976**	70,738	117,224
Total expenses	**279,384**	269,274	322,752
Operating income	**281,822**	250,504	192,147
Interest income and other (Note 4)	**3,929**	10,010	2,703
Interest expense	**(57,490)**	(62,311)	(69,246)
Net income before extraordinary item	**228,261**	198,203	125,604
Extraordinary gain (Note 3)	**-**	-	3,199
Net income	**228,261**	198,203	128,803
Net income attributable to Partners	**225,978**	196,221	127,515
Net income attributable to General Partner	**2,283**	1,982	1,288

Financial data of Alliance Pipeline is detailed in the Annual Report released in the official website, which is shown in Table 49. From Table 49, the total output of 2015, 2016 and 2017 is 514.9 million, 519.8 million and 561.2 million C$, respectively. The total benefit of Alliance Pipeline can be obtained directly from the annual report which is 128.3 million, 198.2 million, and 228.3 million C$, respectively. The preparation of these consolidated financial statements requires management to make estimates and assumptions that affect both the amount and the timing of the recognition of Alliance's assets, liabilities, revenues and expenses and the related disclosures. Management regularly evaluates these estimates utilizing historical experience, consultation with experts and other methods management considers reasonable in the circumstances. Actual results may differ from these estimates. Revisions to accounting estimates are recognized in the period for which the estimate is revised and in any future periods affected. Annual report is the important basis for the formulation of reduction policy.

During the study period (2015, 2016, 2017), affordable penalty of Table 47 can be calculated with the following equation,

$$\text{Affordable penalty} = \text{Total benefit}/\text{Emissions}$$

Five scenarios were discussed in Table 48, which could provide a basis for setting a reduction policy. Taking the year of 2017 as an example, the net benefit with the removal of penalty can be calculated by equations as follows,

$$\text{Penalty} = \text{Carbon tax rate} \times \text{Total emission}$$

$$\text{Net Benefit} = \text{Total benefit} - \text{Penalty}$$

Discussing the penalty under different carbon tax rate scenarios can provide a reference for policy makers, which can compensate the losses caused by the development of companies and is also a constraint.

Alliance’s services offering includes predictable and competitive fixed tolls, a range of transportation options to meet customers’ evolving needs, low-cost rich gas transportation to the Chicago market hub and even more ability to carry natural gas liquids in the gas stream. Alliance also offers seasonal and daily interruptible service.

In addition, the Alliance Trading Pool in Canada, Alliance Chicago Exchange hub services trading point in the U.S., and our listings on the NGX (which provides electronic trading, central counterparty clearing and data services) provide a range of opportunities for other market participants to transact on the pipeline – another first for the company.

Transportation services

For the purpose of protecting the environment, Alliance Pipeline assess operations to look for ways to minimize adverse impacts to air, land, water and wildlife. Mitigative and contingency plans are developed to ensure we meet or exceed applicable government regulations and industry best practices. They actively monitor our pipeline right-of-way and watercourse crossings for erosion events and vegetation cover. The waste and spill prevention plans for new construction, maintenance projects, and facility site operations help the workers ensure appropriate waste disposal and ensure the workers are prepared to respond quickly to any incidents. Alliance’s pipelines are still relatively new and the best proven technology of the day is incorporated into the design of the system, including low emissions compressor stations. The pipeline system boasts higher fuel efficiency and lower levels of air contaminants and greenhouse gas emissions than conventional North American pipelines.

Pipeline in service assets are recorded at cost and are depreciated on a straight-line basis over the estimated useful lives of the assets, commencing from the in service date. Pipeline in service assets include the pipeline, compressor stations, meter stations, capital line pack and other related assets used to provide transmission services. General plant assets consist of field offices and ancillary equipment. These assets are recognized at cost and are depreciated on a straight-line basis over the useful lives of the assets, commencing when the asset is placed in service. Administrative assets include head office furniture and equipment, information systems and leasehold improvements. These assets are recognized at cost and depreciated on a straight-line basis over the useful life of the asset or term of the lease, commencing when the asset is placed in service. Land, capital spares, assets held for sale and assets under construction are recognized at cost and are not subject to depreciation. Additions to property, plant and equipment are recognized at cost. Expenditures included in the costs of property, plant and equipment are reviewed to determine if expenditures increase the output, lower the associated operating costs, or extend the useful life of the assets. Costs not meeting the criteria of the capitalization policy are expensed. When depreciable property is retired or disposed of, the impact is recognized in net income in the period the transaction occurred.

In the mid-90s, pipeline takeaway capacity was a major issue for western Canada's natural gas producers. Restricted capacity on the pipeline network taking gas to market forced producers to compete with each other and weakened wellhead prices. As a result, producers were obliged to sell their natural gas - methane typically containing varying amounts of natural gas liquids such as propane, ethane, butane, and pentane - at a significant price discount compared to what was being earned in U.S. Midwest markets. Bottlenecked gas and depressed prices also meant that the resource owners - British Columbians and Albertans - were losing out on billions in royalty payments. Alliance launched its first open season in September 1996 to secure shipper commitments for transporting 1.325 billion cubic feet per day. When the open season ended in early November, 120 shippers had participated, subscribing to 98 percent of firm capacity. Alliance filed its regulatory application with the FERC on December 24, 1996 and its regulatory application with the NEB on July 3, 1997. The FERC approval came down September 17, 1998. Following what was, at the time, an epic NEB regulatory review process, with more than 3,000 Information Requests and a 77-day public hearing, the NEB granted Alliance Pipeline a Certificate of Convenience and Necessity December 3, 1998. The pipeline construction teams - involving more than 7,000 workers at the height of the project - could now break ground on one of the biggest construction projects going on in North America at the time. In just two years, on December 1, 2000, Alliance Pipeline went into service. Natural gas royalty payments in Alberta alone jumped from $2.4 billion in the 1999/2000 period, prior to Alliance going into service, to $7.2 billion in the 2000/2001 period, Alliance's first year of operation. Over the same 12-month time span, the price producers could fetch for their gas once Alliance was running went up from $2.66 per million cubic feet (mcf) to $6.07 per mcf. Alberta's natural gas royalties fluctuated, but over the next decade were always at least twice what they had been pre-Alliance.

Alliance Pipeline is committed to protecting the environment, which is accomplished by:

- Understanding the potential environmental impacts of our facilities and associated processes;
- Implementing an environmental protection program with processes and procedures that help to proactively manage hazards, potential hazards and risks;
- Training employee-partners to be aware of our environmental aspects and provide the processes so they can successfully complete their tasks in a manner that minimizes impact to the environment;
- Conducting audits and inspections to identify and mitigate environmental impacts;
- Monitoring employee-partners, contractors, and service providers to ensure compliance with regulations and procedures. It is a requirement of anyone working on our facilities that they know and follow the rules;
- Encouraging the reporting of hazards, incidents and regulatory violations without fear of retaliation as supported by our Corporate Code of Business Conduct;
- Preparing ourselves for environmental incidents so that we may respond safely, promptly and effectively;
- Reviewing our environmental performance regularly using measures defined by AIMS, industry, and our regulators;
- Striving for continual improvement by reviewing risks, learning from our incidents, and regularly evaluating our environmental protection program and its performance.

3.12. Affordable penalty analysis of TransCanada Pipelines

Table 50. Affordable penalty summary of TransCanada Pipelines

Year	Total Output (million C$)	Total Benefit (million C$)	Total Emissions (tonne)
2013	4402.70	2466	238885
2014	4338.10	2633.8	602997
2015	4441.40	2582	514416

Table 51. Emission penalty under different scenarios of TransCanada Pipelines

Scenario (carbon tax rate)	Total Benefit (million C$)	Total Emissions (tonne)	Fuel Charge Cost (million C$)	Percentage (%)
10 C$/tonne	2582	514416	5.14	0.2%
20 C$/tonne	2582	514416	10.28	0.4%
30 C$/tonne	2582	514416	15.42	0.6%
40 C$/tonne	2582	514416	20.56	0.8%
50 C$/tonne	2582	514416	25.7	1.0%

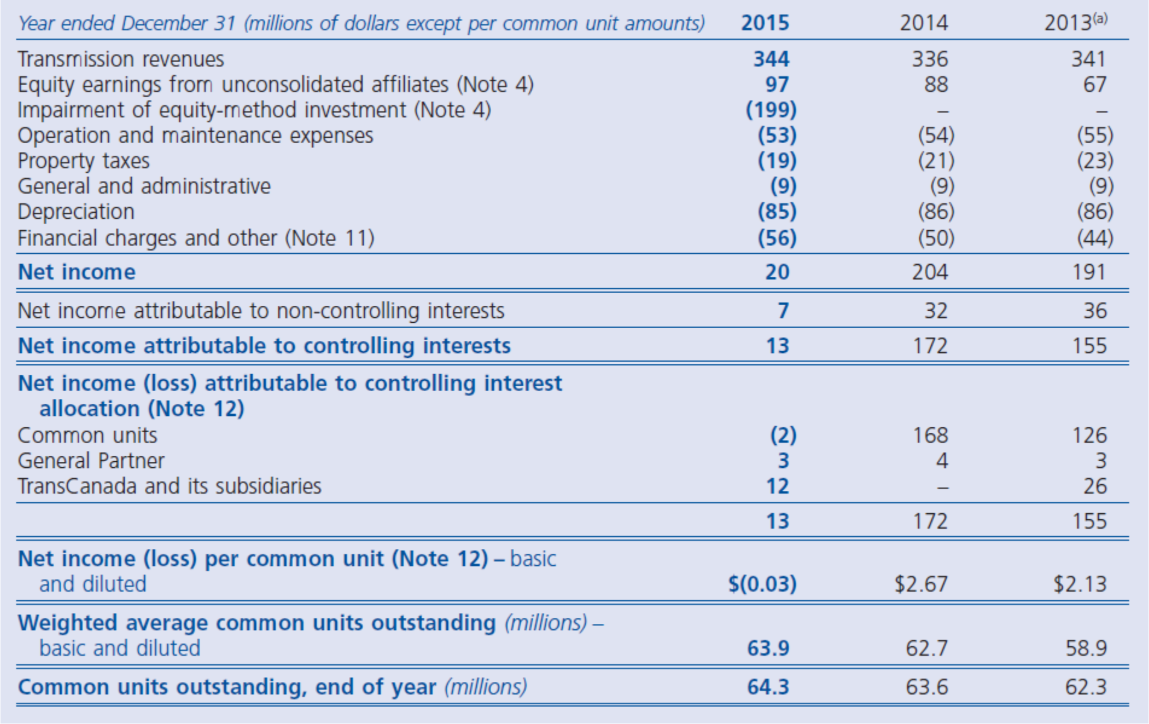
Note: Data of 2015 is taken as an example.

TC PipeLines, LP is a United States limited partnership with a long history of stable and growing cash distributions which has delivered value to its investors while maintaining a solid cash distribution coverage ratio. TC PipeLines, LP was formed by TransCanada Corporation and its subsidiaries (TransCanada) in 1998 to acquire, own and participate in the management of energy infrastructure businesses in North America. Their pipeline systems transport natural gas in the U.S.TC PipeLines, LP (NYSE: TCP) is a publicly traded master limited partnership. TC PipeLines, LP manages and owns natural gas pipelines in the United States including 46.45% of Great Lakes Gas Transmission Limited Partnership, 50% of Northern Border Pipeline Company, 100% of Gas Transmission Northwest, and 100% of Tuscarora Gas Transmission Company. TC PipeLines, LP is based in Calgary, Alberta.

TransCanada is the largest shareholder in, and owns the general partner of, TC PipeLines. The company was founded in 1951 in Calgary. TransCanada is the indirect parent of their General Partner and owns, through its subsidiaries, approximately 25.3 percent of their common units, 100 percent of their Class B units, 100 percent of their IDRs and an effective two percent general partner interest in us. TransCanada is a major energy infrastructure company, listed on the Toronto Stock Exchange and NYSE, with more than 65 years of experience in the responsible development and reliable operation of energy infrastructure in North America. TransCanada's business is primarily focused on natural gas and oil transmission and power generation services. TransCanada consists of investments in 56,900 miles natural gas pipelines, 2,700 miles of wholly-owned oil pipelines and 653 billion cubic feet of natural gas storage capacity. TransCanada also owns or has interests in over 10,700 megawatts of power generation. TransCanada is one of the continent's largest providers of gas storage and related services with approximately 653 billion cubic feet (1.85×1010 m3) of storage capacity. TransCanada operates their pipeline systems and, in some cases, contracts for pipeline capacity. TC PipeLines, LP has purchased assets from TransCanada and jointly participated with TransCanada in acquiring assets from third parties, including acquisitions that TC PipeLines, LP would have been unable to pursue on their own. TransCanada views the Partnership as a core element of its strategy and considers the dropdown of assets into the Partnership as an effective financing option as it executes its capital growth program, subject to actual funding needs and market conditions. There can be no assurance as to when and on what terms these assets will be offered to the Partnership.

We obtain data from TC PipeLines, LP official website. The required data can be obtained from the Annual Report of TC PipeLines, LP as shown in Fig1. We know the revenue of TC PipeLines, LP year by year from 2013 to 2015. For TC PipeLines, LP, the revenue of 2013, 2014 and 2015 is 341 million, 336 million, and 344 million C$, and the net income of 2013, 2014 and 2015 is 191 million, 204 million, and 20 million C$

Table 52. Consolidated statements of income



Year ended December 31 (millions of dollars except per common unit amounts)	**2015**	2014	2013[(a)]
Transmission revenues	**344**	336	341
Equity earnings from unconsolidated affiliates (Note 4)	**97**	88	67
Impairment of equity-method investment (Note 4)	**(199)**	–	–
Operation and maintenance expenses	**(53)**	(54)	(55)
Property taxes	**(19)**	(21)	(23)
General and administrative	**(9)**	(9)	(9)
Depreciation	**(85)**	(86)	(86)
Financial charges and other (Note 11)	**(56)**	(50)	(44)
Net income	**20**	204	191
Net income attributable to non-controlling interests	**7**	32	36
Net income attributable to controlling interests	**13**	172	155
Net income (loss) attributable to controlling interest allocation (Note 12)			
Common units	**(2)**	168	126
General Partner	**3**	4	3
TransCanada and its subsidiaries	**12**	–	26
	13	172	155
Net income (loss) per common unit (Note 12) – basic and diluted	**$(0.03)**	$2.67	$2.13
Weighted average common units outstanding *(millions)* – basic and diluted	**63.9**	62.7	58.9
Common units outstanding, end of year *(millions)*	**64.3**	63.6	62.3

In table 50, Total Output and Total benefit can be obtained by the following equation,

Total Output=Transmission revenues

Total Benefit=Net income

In table 51, Affordable penalty refer to the fines can be incurred without affecting the normal operation of the company, which could be calculated by the following equation,

Affordable penalty =Total benefit/Total Emissions

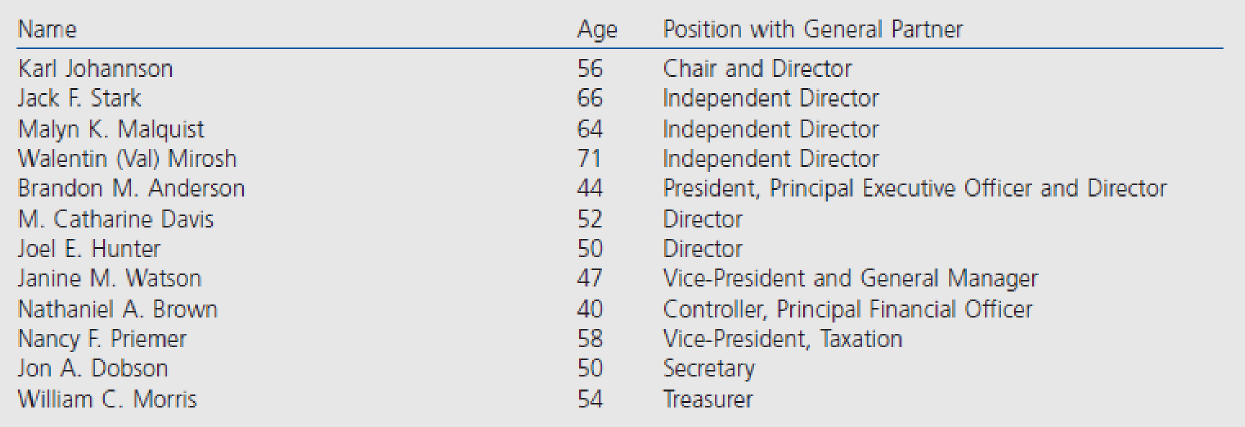
There are five hypothetical scenarios listed in Table 51, which could provide a basis for setting a reduction policy. The carbon tax rate range from 10 C$/tonne to 50 C$/tonne of carbon emission released by the transportation progress. Taking the year of 2015 as an example, the net benefit with the removal of penalty can be calculated by the following equations,

Penalty = Carbon tax rate × Total emission
Net Benefit = Total benefit – Penalty

Discussing the penalty under different carbon tax rate scenarios can provide a reference for policy makers, which can compensate the losses caused by the development of companies and is also a constraint

TC PipeLines, LP is a limited partnership and as such has no officers, directors or employees. Set forth below is certain information concerning the directors and officers of the General Partner who manage the operations of the Partnership. Each director holds office for a one-year term or until his or her successor is earlier appointed. All officers of the General Partner serve at the discretion of the board of directors of the General Partner which is an indirect wholly owned subsidiary of TransCanada.

Table 53. The directors and officers of the General Partner



Name	Age	Position with General Partner
Karl Johannson	56	Chair and Director
Jack F. Stark	66	Independent Director
Malyn K. Malquist	64	Independent Director
Walentin (Val) Mirosh	71	Independent Director
Brandon M. Anderson	44	President, Principal Executive Officer and Director
M. Catharine Davis	52	Director
Joel E. Hunter	50	Director
Janine M. Watson	47	Vice-President and General Manager
Nathaniel A. Brown	40	Controller, Principal Financial Officer
Nancy F. Priemer	58	Vice-President, Taxation
Jon A. Dobson	50	Secretary
William C. Morris	54	Treasurer

Natural gas pipelines move natural gas from major sources of supply or upstream pipelines to downstream pipelines or locations or markets that use natural gas to meet their energy needs. Pipeline systems include meter stations that record how much natural gas comes on to the pipeline and how much exits at the delivery locations; compressor stations that act like pumps to move the large volumes of natural gas along the pipeline; and the pipelines themselves that transport natural gas under high pressure.

Interstate natural gas pipelines are regulated by FERC. FERC approves the construction of new pipeline facilities and regulates aspects of their business including the maximum rates that are allowed to be charged. Maximum rates are based on operating costs, which include allowances for operating and maintenance costs, income and property taxes, interest on debt, depreciation expense to recover invested capital and a return on the capital invested. Although FERC regulates maximum rates for services, interstate natural gas pipelines frequently face competition and therefore may choose to discount their services in order to compete.

Because FERC rate reviews are periodic and not annual, actual revenues and costs typically vary from those projected during the rate case. If revenues no longer provide a reasonable opportunity to recover costs, a pipeline can file with FERC for a determination of new rates, subject to any moratoriums in effect. FERC also has the authority to initiate a review to determine whether a pipeline's rates of return are just and reasonable. Sometimes a settlement or agreement with the pipeline shippers is achieved, which may include mutually beneficial performance incentives. A settlement is ultimately subject to FERC approval.

The North American natural gas pipeline network has been developed to connect supply to market. Use and growth of this infrastructure is affected by changes in the location, relative cost of natural gas supply and changing market demand.

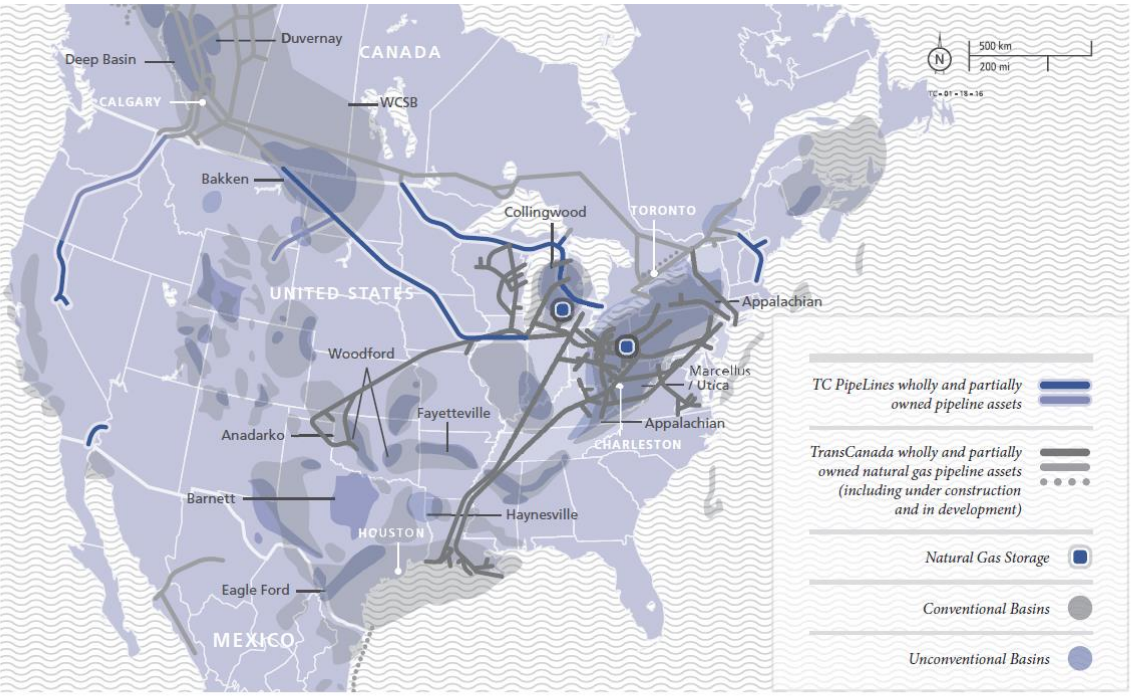


Figure 15. The location of TransCanada Corporation.

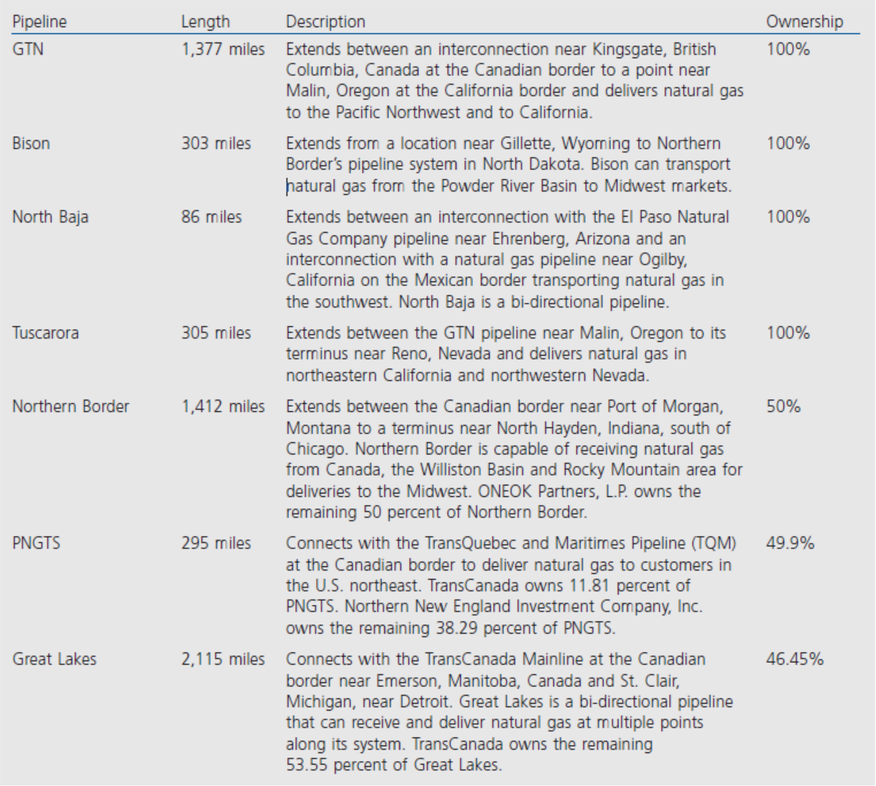
Natural gas is primarily transported from producing regions and, in limited circumstances, from liquefied natural gas (LNG) import facilities to market hubs or interconnects for distribution to natural gas consumers. Recent development of shale and other unconventional gas reserves has resulted in increases in overall North American natural gas production and economically recoverable reserves. There has been an increase in production from the development of shale gas reserves that are located close to traditional markets, particularly in the Northeastern U.S. This has increased the number of supply choices for natural gas consumers resulting in changes to historical natural gas pipeline flow patterns.

The natural gas pipeline business ultimately depends on a shipper's demand for pipeline capacity and the price paid for that capacity. Demand for pipeline capacity is influenced by, among other things, supply and market competition, economic activity, weather conditions, natural gas pipeline and storage competition and the price of alternative fuels.

With interests in approximately 6,300 miles of FERC regulated, interstate natural gas pipelines and a combined total deliverable capacity of 9.4 billion cubic feet per day (bcf/d), their assets are essential infrastructure that supply approximately 13 percent of the average daily U.S. natural gas demand and are well interconnected to the key markets they serve.

TransCanada Pipelines has four wholly-owned pipelines and equity ownership interests in three natural gas interstate pipeline systems that are collectively designed to transport approximately 9.1 billion cubic feet per day of natural gas from producing regions and import facilities to market hubs and consuming markets primarily in the Western, Midwestern and Eastern U.S. All of their pipeline systems are operated by subsidiaries of TransCanada.

Table 54. Ownership interests of TCPLP



Pipeline	Length	Description	Ownership
GTN	1,377 miles	Extends between an interconnection near Kingsgate, British Columbia, Canada at the Canadian border to a point near Malin, Oregon at the California border and delivers natural gas to the Pacific Northwest and to California.	100%
Bison	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison can transport natural gas from the Powder River Basin to Midwest markets.	100%
North Baja	86 miles	Extends between an interconnection with the El Paso Natural Gas Company pipeline near Ehrenberg, Arizona and an interconnection with a natural gas pipeline near Ogilby, California on the Mexican border transporting natural gas in the southwest. North Baja is a bi-directional pipeline.	100%
Tuscarora	305 miles	Extends between the GTN pipeline near Malin, Oregon to its terminus near Reno, Nevada and delivers natural gas in northeastern California and northwestern Nevada.	100%
Northern Border	1,412 miles	Extends between the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana, south of Chicago. Northern Border is capable of receiving natural gas from Canada, the Williston Basin and Rocky Mountain area for deliveries to the Midwest. ONEOK Partners, L.P. owns the remaining 50 percent of Northern Border.	50%
PNGTS	295 miles	Connects with the TransQuebec and Maritimes Pipeline (TQM) at the Canadian border to deliver natural gas to customers in the U.S. northeast. TransCanada owns 11.81 percent of PNGTS. Northern New England Investment Company, Inc. owns the remaining 38.29 percent of PNGTS.	49.9%
Great Lakes	2,115 miles	Connects with the TransCanada Mainline at the Canadian border near Emerson, Manitoba, Canada and St. Clair, Michigan, near Detroit. Great Lakes is a bi-directional pipeline that can receive and deliver natural gas at multiple points along its system. TransCanada owns the remaining 53.55 percent of Great Lakes.	46.45%

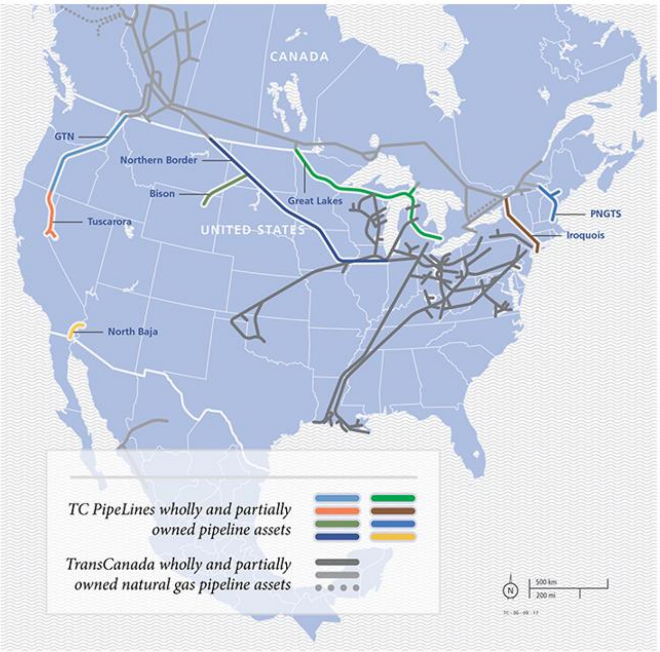


Figure 16. the location of TCPLP pipeline systems

Their pipelines are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including air emissions, water quality, wastewater discharges and waste management. Such laws and regulations generally require natural gas pipelines to obtain and comply with a wide variety of environmental registrations, licenses, permits and other approvals required for construction and operations. Certain violations of environmental laws can result in the imposition of strict, joint and several liability. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and/or criminal penalties, the imposition of investigatory, remedial and corrective action requirements, the occurrence of delays or restrictions in the permitting or performance of projects and/or the issuance of orders enjoining future operations in affected areas. The following is a discussion of some of the applicable environmental laws and regulations that relate to their business.

- Solid Wastes and Hazardous Substance and Wastes Statutes – The operations of their pipeline systems are subject to federal and analogous state statutes that regulate the handling, management, storage and disposal of solid wastes, including hazardous wastes and hazardous substances. These include the Resource Conservation and Recovery Act the Solid Waste Disposal Act and the Comprehensive Environmental Response, Compensation and Liability Act, on the federal level and comparable state statutes. These statutes subject their operations to rigorous waste management and disposal practices to ensure compliance. In addition, the improper disposal or a release of wastes or hazardous substance could result in the imposition of investigatory or remedial obligations.

- The Clean Air Act (CAA) – The CAA and comparable state laws regulate emissions of air pollutants from various industrial sources, including compressor stations, and impose various monitoring, reporting, and in some cases, control requirements. Such laws and regulations may require pre-approval for the construction or modification of certain facilities expected to produce air pollutants or result in an increase of existing air pollutants. Such facilities must also comply with air permits containing various emission and operational limitations, or requiring the use of emission control or abatement technologies, which could result in the imposition of substantial costs on their operations.

- Toxic Substances Control Act (TSCA) – The TSCA addresses the production, importation, use and disposal of specific chemicals and provides the EPA with authority to require reporting, record-keeping and testing requirements, and restrictions relating to chemical substances and mixtures. These include polychlorinated biphenyls (PCBs), asbestos, radon and lead-based paint.

- The Clean Water Act (CWA) and the Oil Pollution Act of 1990 (OPA) – The CWA, OPA and comparable state laws impose strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into or adjacent to state waters and waters of the U.S. The discharge of pollutants into regulated waters is generally prohibited, except in accordance with the terms of a permit issued by the EPA or a delegated state or federal agency. The CWA and federal regulations also prohibit the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit. The EPA released a final rule in May 2015 that attempted to clarify federal jurisdiction under the CWA over waters of the U.S. This interpretation by the EPA may constitute an expansion of federal jurisdiction over waters of the U.S. Implementation of the rule has been stayed nationwide, and in

January 2017, the U.S. Supreme Court accepted review of the rule to determine whether jurisdiction over the challenge to the rule rests with the federal district or appellate courts. Litigation surrounding the rule is ongoing. To the extent the rule expands the scope of the CWA's jurisdiction, pipeline construction and expansion projects could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

- National Environmental Policy Act (NEPA) – Natural gas transportation activities over federally-managed land or involving federal approval can be subject to review under NEPA, or analogous state requirements. NEPA requires federal agencies, including the Department of the Interior or FERC, to evaluate governmental agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that addresses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that is made available for public review and comment. The current activities of their pipeline systems, as well as any proposed plans for future activities, on federal lands are subject to the requirements of NEPA in connection with any new approval that is required for construction, operation or use on or of federal lands. NEPA reviews can take a significant amount of time and are subject to challenge and appeal by environmental groups, who have frequently used the NEPA process to challenge pipeline construction projects over the past several years, and therefore, have the potential to delay current and future natural gas transportation activities.

- The Endangered Species Act (ESA) – The ESA restricts activities that may affect endangered or threatened species or their habitats. The presence of threatened or endangered species, including the designation of previously unidentified or threatened species, could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, and state levels of government to monitor and limit emissions of greenhouse gases (GHGs). At the federal level, no comprehensive climate change legislation has been implemented to date, but the EPA has determined that emissions of GHGs present an endangerment to public health and the environment and subsequently has adopted regulations under existing provisions of the CAA that, among other things, establish construction and operating permit reviews regarding GHGs for certain large stationary sources that are already potential major sources of conventional pollutant emissions. The EPA has also promulgated regulations requiring the monitoring and reporting of GHG emissions from, among other sources, certain onshore natural gas transmission and storage facilities, including gathering and boosting facilities, completions and workovers of oil wells with hydraulic fracturing and blowdowns of natural gas transmission pipelines between compressor stations in the U.S. on an annual basis. Recent federal rulemakings have focused on the emission of methane.

Additionally, while the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, in the absence of any significant activity by Congress in recent years to adopt such legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. For example, Washington, one of the states in which we operate, has implemented a carbon tax that has the potential to impact their operations; however, at this time TC PipeLines, LP does not expect the impact of Washington's carbon tax on their operations to be material.

On an international level in December 2015, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and ‘‘represent a progression’’ in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. The agreement was signed by the U.S. in April 2016 and entered into force in November 2016. The U.S. is one of more than 120 countries having ratified or otherwise consented to the agreement; however, the agreement does not set binding emission reduction targets. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact their business, any such future laws and regulations that limit emissions of GHGs could adversely affect demand for the oil and natural gas that exploration and production operators produce, some of whom are their customers, which could thereby reduce demand for their natural gas transportation services.

Their pipeline systems are subject to federal pipeline safety statutes, such as the Natural Gas Pipeline Safety Act of 1968 (NGPSA), the Pipeline Safety Improvement Act of 2002 (the PSI Act), the Pipeline Inspection, Protection, and Enforcement Act of 2006 (the PIPES Act), the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the 2011 Pipeline Safety Act) and the Protecting Their Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the 2016 Pipeline Safety Act), as well as regulations promulgated and administered by the PHMSA. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities. Pursuant to the authority granted under the NGPSA, PHMSA has promulgated regulations governing pipeline design, installation, testing, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. The PSI Act established mandatory inspections for all U.S. natural gas transportation pipelines, and some gathering lines in high consequence areas (HCAs), which are areas where a release could have the most significant adverse consequences, including high population areas. The PIPES Act required mandatory inspections for certain natural gas transmission pipelines in HCAs and required that rulemaking be issued for, among other things, pipeline control room management. Pursuant to the authority granted under the NGPSA, as amended, PHMSA has established a series of rules requiring pipeline operators, such as us, to develop and implement integrity management programs for natural gas transmission pipelines in HCAs that require the performance of frequent inspections and other precautionary measures. PHMSA may assess penalties for violations of these and other requirements imposed by its regulations. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and also from $1 million to $2 million for a related series of violations.

Additional rulemakings regarding pipeline safety is likely. In June 2016, the 2016 Pipeline Safety Act was passed, extending PHMSA's statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Act and developing new safety standards for natural gas storage facilities by June 22, 2018. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as further amended by the 2016 Pipeline Safety Act, as well as any implementation of PHMSA rules or any issuance or reinterpretation of guidance by PHMSA or any other state agencies with respect thereto, could require us to install new or modified safety controls, pursue additional capital projects, conduct maintenance programs on an accelerated basis, or result in a temporary or permanent reduction in maximum allowable operating pressure, which would reduce available capacity on their pipelines, any or all of which could result in their incurring increased operating costs that could be significant, and have a material adverse effect on their results of operations or financial condition.

From time to time, despite compliance with applicable rules and regulations, their pipelines may experience incidents that result in leaks and ruptures that may impact the surrounding population and environment. This may result in enforcement by regulatory agencies that may seek civil and/or criminal fines and penalties, and could require their pipelines to conduct testing of the pipeline system or upgrade segments of a pipeline unrelated to the incident which costs may not be covered by insurance or recoverable through rate increases.

4. Real Reduction Ability Analysis

4.1. Real reduction ability analysis of Mining-coal

Table 55. Real reduction ability of Mining-coal industry

Project Component	**Total Annual Baseline Emission (tCO_2e/yr.)**	**Total Annual Project Emission (tCO_2e/yr.)**	**Total Annual Emission Reduction (tCO_2e/yr.)**	Rate of mitigation
CMM to power/heat	134,345	21,750	112,592	83.8%
VAM to heat	155,678	30,393	125,285	80.5%
Combined CMM to power/heat and VAM to heat	290,023	52,143	237,880	82.0%

The greatest source of greenhouse gas emissions from mining coal arise from so called “fugitive emissions”. All coal seams contain some level of gases, most commonly a mix of carbon dioxide (CO_2) and methane (CH_4). These gases are released when the coal is mined, and this release is referred to as fugitive emissions.

Both surface and underground mines, although contribute about 6% of global emission, has the potential to be significant contributors to overall GHG emission. Inherent within the coal's structure, methane desorbs from the coal's internal surfaces during the mining process, and then moves to the atmosphere through a mine's ventilation system. The unit operations of opencast mining demand high energy and it directly and indirectly contribute GHG emission. Emissions from stock piles of coal/waste also contribute to carbon emission.

The selection of an effective methane control system depends on the sources of the gas emissions. The most commonly applied methane control solution, especially in high in-place gas content coal beds, is drilling methane drainage boreholes into the panel area prior to longwall mining to reduce the methane content of the coal bed. These boreholes can be vertical or horizontal boreholes drilled from the surface, or in-seam horizontal boreholes drilled from the underground entries

Coal mine methane (CMM) is a general term for all methane released mainly during and after mining operations. CMM shows great variability in flow rate and composition. Ventilation air methane (VAM): Methane emitted from coal seams that enters the ventilation air and is exhausted from the ventilation shaft at a low concentration, typically in the range of 0.01 percent to 1.0 percent by volume, whereas gas drained from the seam before mining can contain 60% to more than 95% methane depending on the presence of other gasses in the coal seam. Gas drained from fractured formations above mined seams (gobs), on the other hand, may contain 30–95% methane depending on the locations of the boreholes and other operation and completion parameters. Although ventilation air methane (VAM) from shafts of active mines contributes approximately 64% of worldwide methane emissions from underground coal mines, methane concentrations in the ventilation air are different for each mine. These varying concentrations impact the choice of potential capture and utilization technologies for VAM. With few exceptions, it is simply released to the atmosphere. The high volumetric flowrate and low concentrations of VAM (i.e., less than 1 percent) make it challenging to capture and utilize cost-effectively. It is technically possible, however, to convert the dilute methane in ventilation air to useful energy and the economic feasibility of these projects are currently being developed, demonstrated, and commercialized. There are three primary incentives for recovering CMM. The first and foremost reason is to improve the safety of the mines. The second benefit of recovering CMM is to improve mine economics by allowing the mines to produce coal with minimum downtimes due to high methane levels. The third incentive is to reduce greenhouse gas emissions involving methane, which is about 21 times more potent than CO_2. Capturing high concentrations of methane using boreholes, upgrading it to pipeline quality gas if needed, and utilizing this gas are fairly well-developed techniques.

4.1.1. Benefits of capturing and utilizing CMM and mitigating CMM emission

There are many benefits for recovering and utilizing CMM, including: reducing greenhouse gas emissions; conserving a local source of valuable, clean-burning energy; enhancing mine safety by reducing in-mine concentrations of methane; and providing revenue to mines. Methane capture and use can add significant value to a mining operation. Captured CMM can be directly used to supply or generate energy, harnessing the value of a natural resource. In turn, this can deliver economic returns to the mine through energy sales or cost savings. Moreover, methane utilization adds intrinsic value by generating capital that can be reinvested in mine safety equipment and operations. CMM capture projects may experience financial benefits from pipeline sales revenue, reduced power, heating and/or cooling costs from onsite electricity generation, and in qualifying countries for carbon reduction credit revenue from GHG reduction programs such as CDM (Clean Development Mechanism), JI (Joint Implementation), and voluntary carbon credits. Revenue streams from carbon emission reduction credits can come in the form of Verified Emission Reductions (VERs), Certified Emission Reductions (CERs), or other credits such as emission reduction units (ERUs). These potential carbon-financing options may be a critical factor in making some CMM utilization projects economically viable that would be otherwise financially unattractive. In addition, carbon financing may provide the only revenue streams for abatement-only projects, such as ventilation air methane (VAM) oxidation (without energy recovery) or CMM flaring. VAM can also be used for electric or thermal power generation. At this time, VAM-derived power generation is not commercially feasible without carbon revenues or other incentives, such as preferential electricity pricing or portfolio standards. VAM projects are reported to deliver positive rates of return at carbon prices starting as low as US \$5–\$10/tCO_2e.

Currently, investment decisions at most mines are likely to favor expansion in coal production rather than development of CMM utilization projects (particularly power generation) due to the high opportunity cost of investing in power generation capital equipment and infrastructure. To meet environmental protection targets in the future, however, mine owners may be required to improve gas drainage performance beyond the level strictly required to meet the safety needs of the mines. Such improvements in the drainage system that yield relatively high-quality gas may provide an additional incentive for investment in gas recovery and utilization projects.

Increased methane recovery also reduces methane-related mining delays, resulting in increased coal productivity. Furthermore, the development of methane recovery and use projects has been shown to result in the creation of new jobs, which has helped to stimulate area economies. Additionally, the development of local CMM resources may result in the availability of a potentially low-cost supply of gas that could be used to help attract new industry to a region. For these reasons, encouraging the development of CMM recovery and use projects is likely to be of growing interest to state and local governments that have candidate mines in their jurisdictions. CMM emissions from active underground mines may be mitigated by the implementation of methane drainage systems followed by recovery and use projects. Mines can use several reliable degasification methods to drain methane. These methods have been developed primarily to supplement mine ventilation systems that were designed to ensure that methane concentrations in underground mines remain within safe levels. Degasification systems include vertical wells (drilled from the surface into the coal seam months or years in advance of mining), gob wells (drilled from the surface into the coal seam just prior to mining), and in-mine boreholes (drilled from inside the mine into the coal seam or the surrounding strata prior to mining).

4.1.2. CMM utilization technologies

CMM is gathered from underground mines and brought to the surface via vertical frac wells, surface-drilled horizontal wells, gob wells, and centralized vacuum stations, which collect the gas produced by in-mine boreholes and VAM systems. Not all of the extracted gas is or can be commercially utilized, but depending upon the gas quality and volumes the CMM could be used in a variety of projects, including:

- Natural gas pipeline injection;
- Power generation;
- Ventilation air methane oxidation;
- Power electricity generators for the mine or local region;
- Use as an energy source: co-firing in boilers, district heating, coal drying;
- Use as a vehicle fuel, and manufacturing or industrial uses such as ammonia production;
- Flaring.

Currently, commercial CMM utilization is not technically nor economically viable at many CMM drainage projects worldwide. As a result, the drained gas is vented directly to the atmosphere via an exhauster/well head blower. Most of the more than 300 active underground coal mines in the U.S. do not recover and use methane. One option to reduce the environmental impact of direct venting is to combust the vented methane in a controlled flare system. CMM flaring has been used successfully in Europe and Australia, but has yet to gain widespread acceptance in the U.S. coal mining industry.

The following Figure 17 illustrates several CMM capture and use technologies (and destruction technologies) integrated at an active underground coal mine. The example demonstrates how methane can be used directly to supply or generate energy, which in turn can deliver economic returns for the mine through energy sales or cost savings. Good gas drainage standards and practices will yield gas of stable and usable quality, and will facilitate application of the lowest-cost utilization opportunities. Due to constantly changing mining conditions, gas supply can fluctuate in quality or quantity; thus utilization equipment will occasionally fail or need to be shut down. In these cases, the unused gas can possibly be flared (if N25% methane) to minimize emissions. Methane that cannot be used nor flared can be diluted in ventilation air and can be oxidized via a VAM destruction technology.

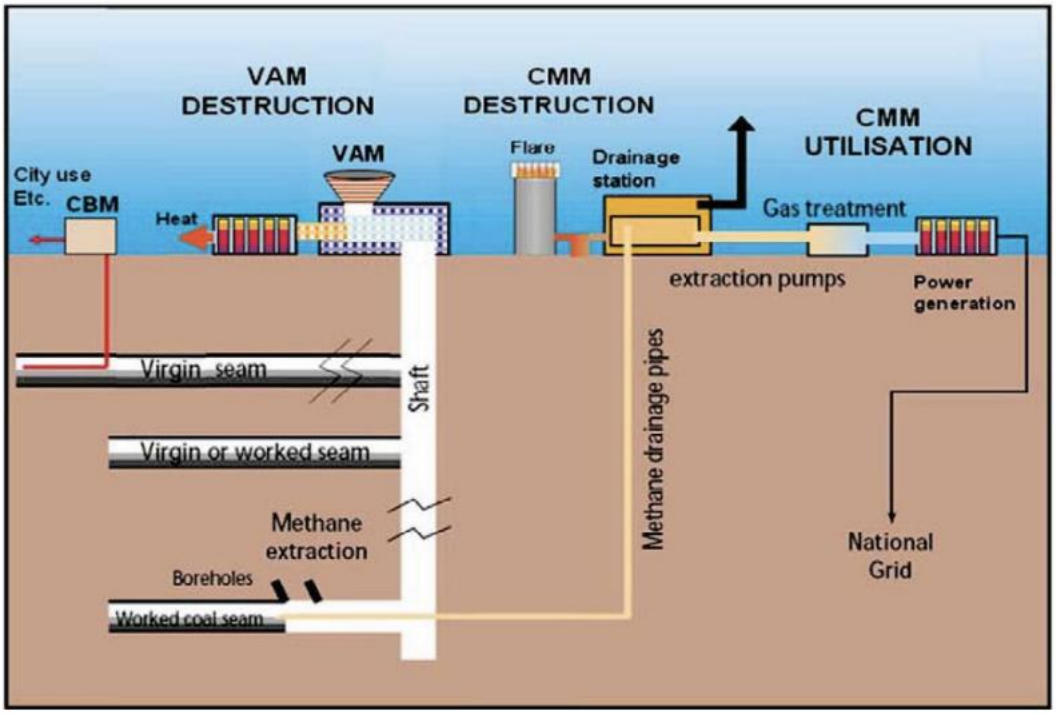
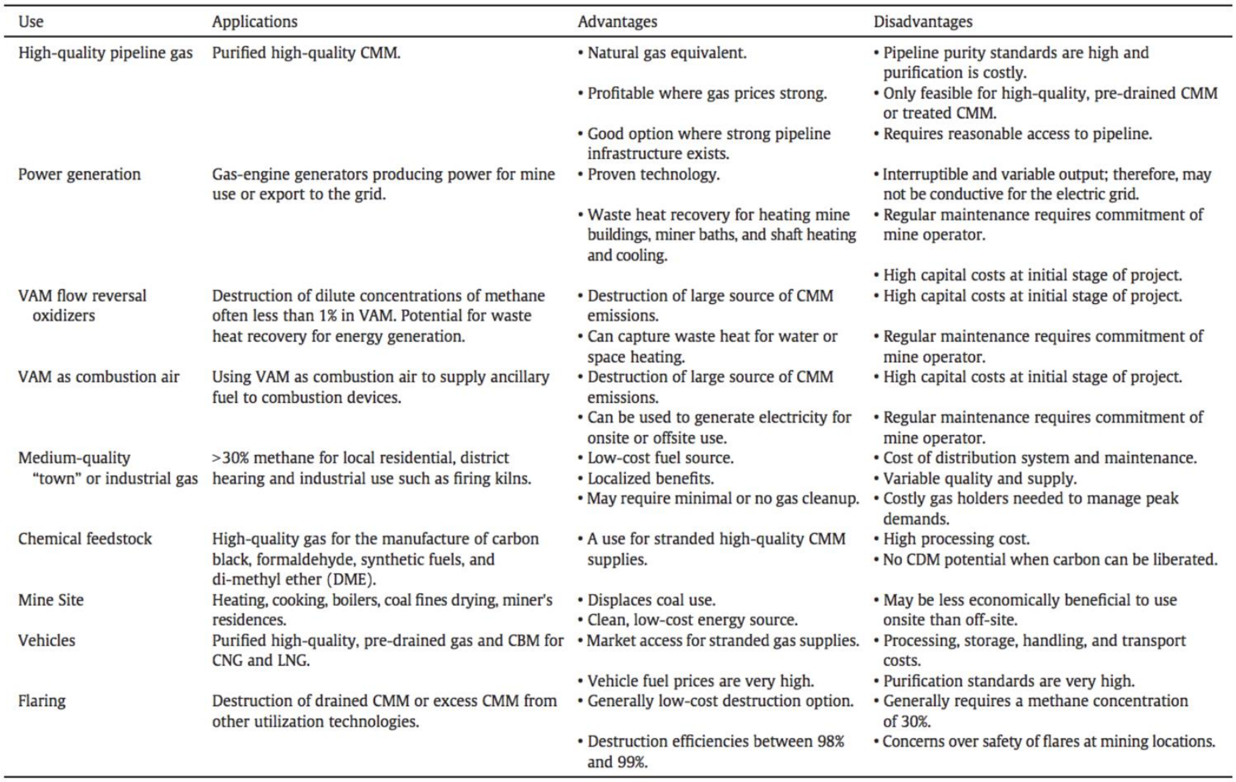


Figure 17. Multiple CMM end-use and destruction options for underground coal mines. Courtesy of Sindicatum Carbon Capita

Each end-use technology has associated advantages and disadvantages. Table 56 summarizes the most common advantages and disadvantages for each of the primary end-use technologies utilized at coal mines globally.

Table 56. Summary of advantages and disadvantages of end-use technologies



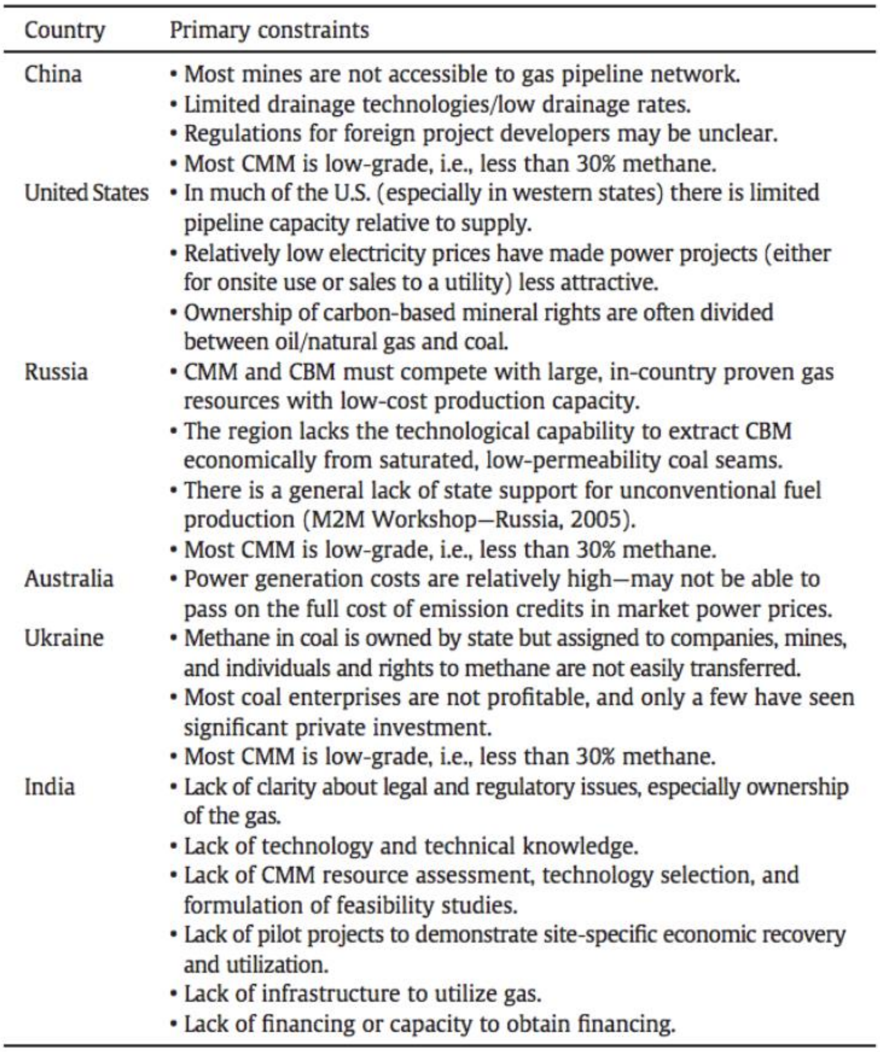
Use	Applications	Advantages	Disadvantages
High-quality pipeline gas	Purified high-quality CMM.	• Natural gas equivalent. • Profitable where gas prices strong. • Good option where strong pipeline infrastructure exists.	• Pipeline purity standards are high and purification is costly. • Only feasible for high-quality, pre-drained CMM or treated CMM. • Requires reasonable access to pipeline.
Power generation	Gas-engine generators producing power for mine use or export to the grid.	• Proven technology. • Waste heat recovery for heating mine buildings, miner baths, and shaft heating and cooling.	• Interruptible and variable output; therefore, may not be conductive for the electric grid. • Regular maintenance requires commitment of mine operator. • High capital costs at initial stage of project.
VAM flow reversal oxidizers	Destruction of dilute concentrations of methane often less than 1% in VAM. Potential for waste heat recovery for energy generation.	• Destruction of large source of CMM emissions. • Can capture waste heat for water or space heating.	• High capital costs at initial stage of project. • Regular maintenance requires commitment of mine operator.
VAM as combustion air	Using VAM as combustion air to supply ancillary fuel to combustion devices.	• Destruction of large source of CMM emissions. • Can be used to generate electricity for onsite or offsite use.	• High capital costs at initial stage of project. • Regular maintenance requires commitment of mine operator.
Medium-quality "town" or industrial gas	>30% methane for local residential, district hearing and industrial use such as firing kilns.	• Low-cost fuel source. • Localized benefits. • May require minimal or no gas cleanup.	• Cost of distribution system and maintenance. • Variable quality and supply. • Costly gas holders needed to manage peak demands.
Chemical feedstock	High-quality gas for the manufacture of carbon black, formaldehyde, synthetic fuels, and di-methyl ether (DME).	• A use for stranded high-quality CMM supplies.	• High processing cost. • No CDM potential when carbon can be liberated.
Mine Site	Heating, cooking, boilers, coal fines drying, miner's residences.	• Displaces coal use. • Clean, low-cost energy source.	• May be less economically beneficial to use onsite than off-site.
Vehicles	Purified high-quality, pre-drained gas and CBM for CNG and LNG.	• Market access for stranded gas supplies. • Vehicle fuel prices are very high.	• Processing, storage, handling, and transport costs. • Purification standards are very high.
Flaring	Destruction of drained CMM or excess CMM from other utilization technologies.	• Generally low-cost destruction option. • Destruction efficiencies between 98% and 99%.	• Generally requires a methane concentration of 30%. • Concerns over safety of flares at mining locations.

Currently, the top two producers of coal and emitters of CMM are China followed by the United States (U.S.). Other large coal producers include Russia, Australia, the Ukraine, and India. Over the past ten years, CMM emissions have been gaining greater attention due to their status as a greenhouse gas (GHG) and their potential use as a clean energy resource. As a result, many countries have begun to perform periodic inventories of their CMM emissions. We list two cases below for CMM capture and utilization technologies.

4.1.3. CMM project barriers

Currently, a number of commercial and institutional barriers (and other project risks) can alter the ultimate economic viability of CMM projects. These obstacles include technical challenges with varying gas quality and quantity, unresolved legal issues concerning ownership of the CMM resource, lack of pilot projects for new technologies to demonstrate site-specific economic recovery and utilization, lack of financing or capacity to obtain financing, and pipeline locality and/or capacity constraints. The above constraints will vary from country to country. For example, in China, barriers to CMM development include lack of accessibility to pipeline networks and limited drainage technologies and low drainage rates. In the U.S., unresolved legal issues (especially of federal lands in the western U.S.) and lack of financing present larger challenges to CMM project development. Conversely, mine locality-to-pipeline networks and access to highly efficient CMM drainage technologies are not barriers in the U.S. The barriers and constraints for some of the large CMM-emitting countries are presented in Table 57.

Table 57. Constrains to CMM development for top CMM emitting countries



Country	Primary constraints
China	• Most mines are not accessible to gas pipeline network. • Limited drainage technologies/low drainage rates. • Regulations for foreign project developers may be unclear. • Most CMM is low-grade, i.e., less than 30% methane.
United States	• In much of the U.S. (especially in western states) there is limited pipeline capacity relative to supply. • Relatively low electricity prices have made power projects (either for onsite use or sales to a utility) less attractive. • Ownership of carbon-based mineral rights are often divided between oil/natural gas and coal.
Russia	• CMM and CBM must compete with large, in-country proven gas resources with low-cost production capacity. • The region lacks the technological capability to extract CBM economically from saturated, low-permeability coal seams. • There is a general lack of state support for unconventional fuel production (M2M Workshop—Russia, 2005). • Most CMM is low-grade, i.e., less than 30% methane.
Australia	• Power generation costs are relatively high—may not be able to pass on the full cost of emission credits in market power prices.
Ukraine	• Methane in coal is owned by state but assigned to companies, mines, and individuals and rights to methane are not easily transferred. • Most coal enterprises are not profitable, and only a few have seen significant private investment. • Most CMM is low-grade, i.e., less than 30% methane.
India	• Lack of clarity about legal and regulatory issues, especially ownership of the gas. • Lack of technology and technical knowledge. • Lack of CMM resource assessment, technology selection, and formulation of feasibility studies. • Lack of pilot projects to demonstrate site-specific economic recovery and utilization. • Lack of infrastructure to utilize gas. • Lack of financing or capacity to obtain financing.

4.1.4. Hebi No.6 Coal Mine, Hebi Coal Field Henan Province, China: Feasibility Study for Coal Mine Methane Drainage and Utilization

This feasibility study was sponsored by the United States Environmental Protection Agency (USEPA) in support of the U.S. - China Strategic Economic Dialogue.

Hebi Mine No.6, located in the Hebi mining area of northern Henan province. It produces 1.2 million tons of coal a year and has a projected production life of 80 years, giving ample time for a long term CMM capture and use project. Methane with an average concentration of 20% is drained from the mine and is used to power five Shengli reciprocating engines which generate approximately 50% of the mine's electricity needs.

(1) Evaluation of Degasification Technologies

Current pre-mining drainage practices at Hebi No. 6 mine include:

- Face drainage, consisting of short fan boreholes drilled in advance of gate developments,

- Gallery drainage, comprised of short fan boreholes drilled into future longwall panels from galleries driven below the mining seam, and cross-panel boreholes drilled from gate entries in advance of longwall mining.

Gob gas drainage practices implemented at Mine No. 6 include: horizontal gob boreholes drilled from galleries developed above the mining seam, and pipe laid in the gob to recover gas generated from remnant coal, or from sealed gob areas.

Reservoir modeling of cross-panel gas drainage indicated that directionally drilling the drainage boreholes would have multiple benefits over the current non-directional drilling method. The new technique will reduce residual gas contents to below those achieved with the current system over the same drainage period, particularly for the lower benches of the coal seam. This system would recover 24 percent more methane than current practices. The reduction in residual gas content of the lower benches reduces methane emissions into the gob by an average of 18.5 percent. Other benefits of this system relative to current practices include:

- 50 percent fewer boreholes drilled;
- 83 percent fewer drill setups, borehole collars, standpipes, and wellheads;
- Fewer wellheads minimizes potential for air intrusion into gathering system, improves recovered gas quality;
- Fewer boreholes reduces methane drainage costs;
- Potential reduction in drainage time by reducing borehole spacing from 12 m to 11 m;
- Fewer boreholes provides for reduced time required for drilling;
- A 15 percent increase in gas content reduction after 21 months;
- Reduced residual gas contents improves mine safety;
- Reduced residual gas contents enable increased coal production.

Directional drill units can also be used to drill drainage boreholes in advance of gate road development. The current system of drainage involves drilling a fan array of short boreholes into the gate road face and degassing for only 12 hours before mining. Directionally drilled boreholes should be drilled in conjunction with the cross-panel boreholes and maintained ahead of gate developments as far as possible. The benefits of this system over the current system are:

- Reduced gas contents in advance of gate development;
- Fewer drill setups to interrupt face advance;
- The structure of coal seam can be defined in advance of developments;
- Outburst zones can be detected further in-by gate developments,
- Improved mine safety,
- Increased mining rates.

It is also recommended to directionally drill gob boreholes over the length of the longwall panel, instead of the current practice of drilling multiple boreholes from an overlying gallery. Benefits include:

- Three wellheads per panel compared to up to 35;
- No overlying drilling galleries required saving on infrastructure development costs;
- Minimizes potential for air intrusion into the gas collection system and provides for improved recovered gob gas quality, and;
- Fewer collars provides for better vacuum control and monitoring.

(2) Suggested improvements to the underground gas gathering system include use of High Density

Polyethylene (HDPE) pipe instead of steel pipe, the installation of pipeline integrity safety systems and the installation of upgraded measuring and monitoring equipment. If all these recommendations are implemented at the mine, it is estimated that the methane drainage rate would increase by 25% from 23,000 m^3/day to 28,750 m^3/day and the average recovered gas quality would increase from under 20% CH_4 to over 50% CH_4.

Table 58. Projected increase in methane drainage volume and recovered gas quality for Hebi Mine No. 6.

CMM Drainage Method	Averaged Recovered Gas Quality (% CH_4)	Methane Drainage Rate (m^3/day) STP
Current	17-21	23,000
Recommended	50-70	28,750

4.1.5. Emission Reductions from Project Implementation

The Hebi Mine No.6 degasification project is intended to reduce methane emissions vented to the atmosphere during the mining process. This will be achieved by increased pre-mining methane drainage from the coal seams, more efficient capture of gob gas emissions, and destruction of ventilation air methane at the surface. Drained methane will be used for electricity generation.

The proposed project at Mine No. 6 contributes to China's sustainability by providing domestically-produced clean energy and by reducing emissions of greenhouse gases (GHG) that would otherwise be emitted to the atmosphere. Since methane (CH_4) is a greenhouse gas (GHG) with a global warming potential (GWP) over 20 times greater than carbon dioxide (CO_2), projects that capture and utilize or destroy methane have the capacity to generate a considerable amount of carbon offsets in the process. Using the framework provided through the clean development mechanism (i.e., approved consolidated methodology ACM0008), potential emission reductions from the proposed project activity were quantified.

The recommended project approach will upgrade the degasification system and utilize methane liberated from Mine No. 6 in two ways. Firstly, new gas engines with a total capacity of 2.5 MW will be added to the 5 existing gas engines in order to utilize 100% of the extracted CMM to produce electricity and heat. The power produced will be used for the mine's own consumption, replacing electricity that would otherwise be purchased from the Central China Power Grid (CCPG). Waste heat from the engines will be utilized to supply hot water to nearby mining facilities. Secondly, up to two units of a newly developed methane oxidation technology will be installed at the East Wing ventilation shaft to destroy ventilation air methane with low CH_4 concentrations (below 1%). This technology will also produce thermal energy that can be substituted for coal-based heat.

Total emission reductions over a ten-year crediting period are estimated at 2,378,800 tCO_2e. Table 59 summarizes baseline and annual emissions, as well as annual emission reductions, by project component.

Table 59. Annual emissions and emission reductions by project component

Project Component	Total Annual Baseline Emissions (tCO_2e/yr)	Total Annual Project Emissions (tCO_2e/yr)	Total Annual Emission Reductions (tCO_2e/yr)
CMM-to-power/heat	134,345	21,750	**112,592**
VAM-to-heat	155,678	30,393	**125,285**
Combined CMM-to-power/heat and VAM-to-heat	290,023	52,143	**237,880**

4.1.6. Capital and Operating Costs; Economic and Financial Analysis

Hebi Mine No.6 currently drains an average of approximately 8.4 million m^3 of coal mine methane (100% CH_4) each year and uses 5.76 million m^3 of the gas to produce half of the mine's annual electricity needs. It is proposed in this feasibility study that upgrading the mine's methane drainage systems and techniques, would result in a 25% increase in methane drainage (to 10.5 million m3 per year).

The main capital costs for the methane drainage upgrading include the purchase of two sets of directional drilling equipment; the purchase of two sets of HDPE pipe fusion equipment; a pipeline integrity and monitoring system; and subsequent training of the mine staff on all new equipment. This is estimated to total $4,193,000. The recommended new methane drainage system of multi-layer directional in-seam drilling will result in approximately the same total length of drill hole (drilled per year) as under the current drilling system. The proposed new system of draining the gob will negate the current technique of mining overlying drilling galleries. Therefore, overall drilling costs associated with the new methane drainage system are expected to be less than, or equivalent, to current expenses. New electricity generating capacity will be purchased and initial cost, including installation, is calculated at $739 per kw.

The economics of three potential scenarios of VAM utilization (abatement only, heat generation, and power generation) are detailed in the Appendices. Abatement of VAM while generating heat is calculated to be the most economic scenario, with a capital expenditure of US$6.5 million paid back in 4.2 years and producing an Internal Rate of Return of 24% over 15 years.

4.1.7. Methane Utilization Technologies

The ability to utilize methane produced from degasification systems has grown with advances in gas processing and power generation technologies. In China, these advances now allow for CMM with methane concentrations as low as 20%1 to be commercially utilized, and methods for utilizing methane in concentrations of 1% or less (VAM) are currently in the early stages of commercialization. In this section, possible methods of utilizing the drained CMM from Hebi Mine No. 6 are technically evaluated. These include:

- Firing or cofiring boilers for hot water production and space heating
- Direct use (cooking and heating) in residential areas
- Fueling reciprocating engines for electricity generation
- Feedstock for gas enrichment systems which upgrade gas to pipeline quality
- Conversion to liquid natural gas (LNG)
- Conversion to compressed natural gas (CNG)
- Flaring
- Ventilation air methane (VAM) capture to fuel electricity generation

4.1.8. Best Practices in CMM Utilization: Achieving Near-Zero Methane Emissions from Coal Mine Mining:

Sindicatum Sustainable Resources Group, along with its Chinese partners Shanxi Coking Coal Group and Xishan Coal and Electricity Company, are delighted to announce that they have successfully established the world's first demonstration of the principle of near zero methane emission mining ("nZEM") at the Duerping coal mine in Shanxi Province, China.

At Duerping, a ventilation air methane (VAM) abatement project, together with a coal mine methane (CMM) capture and utilization project, combine:

- The use of gas captured in the mine for power generation and heat recovery;
- The destruction by flaring of any unused gas; and,
- The abatement of the uncaptured gas which has been diluted in the air stream of the mine to allow safe working.

The CMM co-generation plant is fully operational and the final component in the picture is the VAM abatement project which achieved registration under the Clean Development Mechanism on 13 February 2012. The VAM abatement equipment is under construction and the first phase of the installation will be completed by September 2012. The full set of VAM equipment will reduce emissions of the very dilute methane in ventilation air by 200,000t CO_2 equivalent each year.

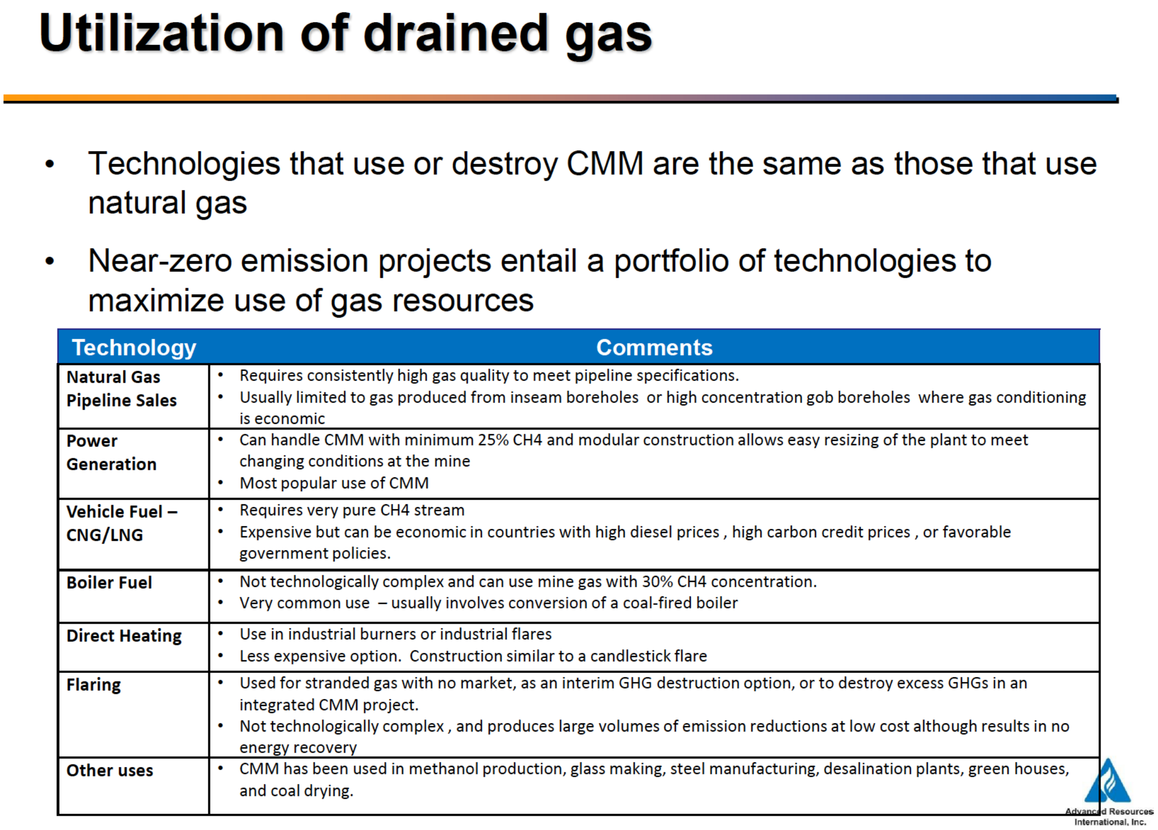
Each year, the ZEM project will reduce methane emissions from Duerping coal mine by up to 536,000 tonnes of CO_2 equivalent and in excess of 70,000MWh of clean power will be generated. Waste heat is recovered and used to heat the mine intake air in the cold winters replacing polluting coal boilers and improving underground working conditions. Improved road infrastructure to access the CMM power plant site has benefitted the communications and trade of surrounding villages. Jobs have been created to support construction, site operations and the new service industries needed to support the imported equipment and technology.

Two technologies are being employed to destroy the ventilation air methane, thermal oxidation and catalytic oxidation. The latter, known as the "CH_4MIN" technology has been licensed exclusively to Sindicatum by Natural Resources, Canada (NRCan) who are also providing technical support. The Duerping VAM project marks the world's first commercial full-scale demonstration of the CH_4MIN technology at a coal mine.

The equipment and installation is being designed, constructed and installed by Megtec Inc. and its Shanghai subsidiary, world leaders in the manufacture and supply of VAM technology. The equipment is fully financed by Sindicatum, who are also supervising the construction of the project on behalf of its Chinese partner.

Sindicatum has financed and oversees the operations of CMM power plants with heat recovery and flaring of unused gas at Duerping, Tunlan and Malan coal mines in Shanxi Province, China. These plants provide a total of 27MW of clean power generation. By the end of 2011, over 192,000MWh of electricity had been produced and cumulative methane emissions reduced equivalent to 1,154,690 t of CO_2. Sindicatum's international engineering team is working with the coal mines to ensure gas flows and qualities are maintained and also to enhance gas management and underground safety. The combination of three CMM and one VAM project will eliminate 1 million tonnes of CO_2 equivalent of methane emissions annually.

Sindicatum, through its U.S. company Verdeo, plans to develop a similar scale of coal mine related projects in the United States and a first VAM abatement project is already in the final stages of construction at the McElroy mine in West Virginia, one of the largest underground coal mines in the U.S. The project will reduce emissions by approximately 380,000t of CO_2 equivalent per year when it becomes operational in the second quarter of 2012.

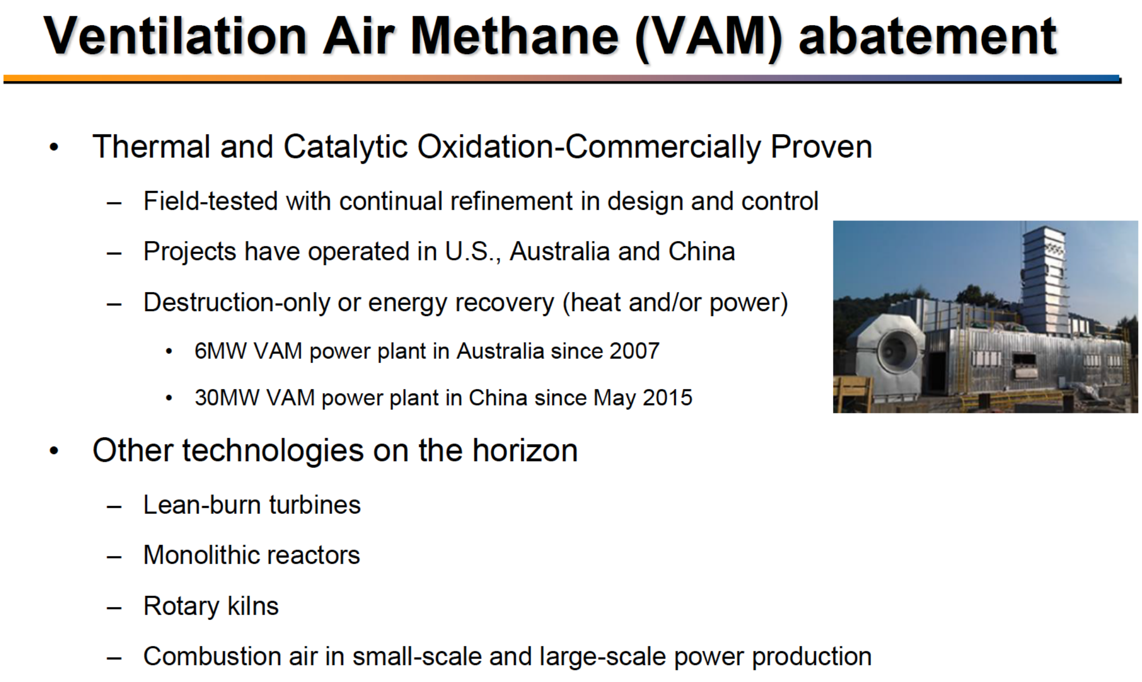


Utilization of drained gas

- Technologies that use or destroy CMM are the same as those that use natural gas
- Near-zero emission projects entail a portfolio of technologies to maximize use of gas resources

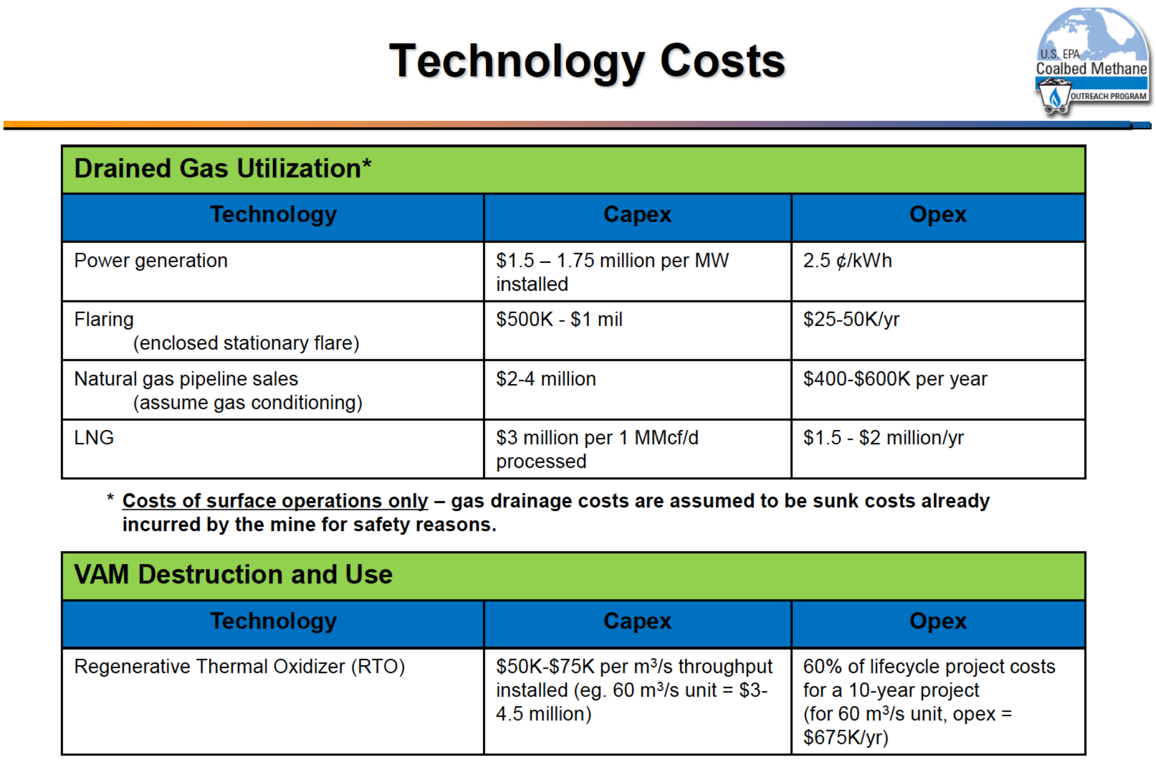
Technology	Comments
Natural Gas Pipeline Sales	• Requires consistently high gas quality to meet pipeline specifications. • Usually limited to gas produced from inseam boreholes or high concentration gob boreholes where gas conditioning is economic
Power Generation	• Can handle CMM with minimum 25% CH4 and modular construction allows easy resizing of the plant to meet changing conditions at the mine • Most popular use of CMM
Vehicle Fuel – CNG/LNG	• Requires very pure CH4 stream • Expensive but can be economic in countries with high diesel prices , high carbon credit prices , or favorable government policies.
Boiler Fuel	• Not technologically complex and can use mine gas with 30% CH4 concentration. • Very common use – usually involves conversion of a coal-fired boiler
Direct Heating	• Use in industrial burners or industrial flares • Less expensive option. Construction similar to a candlestick flare
Flaring	• Used for stranded gas with no market, as an interim GHG destruction option, or to destroy excess GHGs in an integrated CMM project. • Not technologically complex , and produces large volumes of emission reductions at low cost although results in no energy recovery
Other uses	• CMM has been used in methanol production, glass making, steel manufacturing, desalination plants, green houses, and coal drying.

Advanced Resources International, Inc.



Ventilation Air Methane (VAM) abatement

- Thermal and Catalytic Oxidation-Commercially Proven
  - Field-tested with continual refinement in design and control
  - Projects have operated in U.S., Australia and China
  - Destruction-only or energy recovery (heat and/or power)
    - 6MW VAM power plant in Australia since 2007
    - 30MW VAM power plant in China since May 2015
- Other technologies on the horizon
  - Lean-burn turbines
  - Monolithic reactors
  - Rotary kilns
  - Combustion air in small-scale and large-scale power production



Technology Costs

Drained Gas Utilization*

Technology	Capex	Opex
Power generation	$1.5 – 1.75 million per MW installed	2.5 ¢/kWh
Flaring (enclosed stationary flare)	$500K - $1 mil	$25-50K/yr
Natural gas pipeline sales (assume gas conditioning)	$2-4 million	$400-$600K per year
LNG	$3 million per 1 MMcf/d processed	$1.5 - $2 million/yr

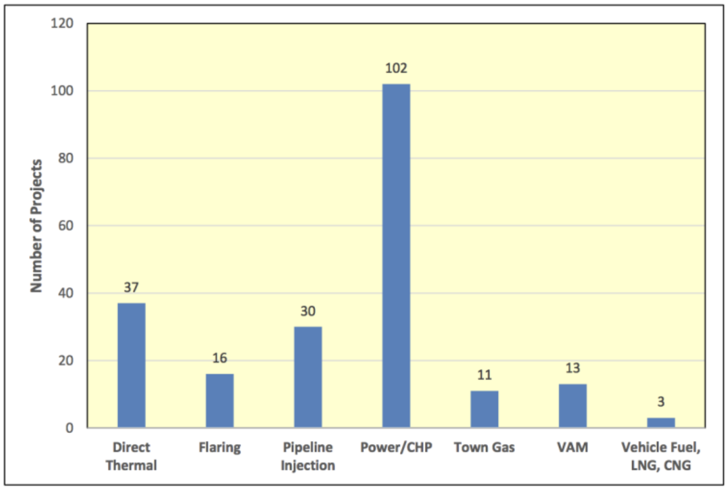
* **<u>Costs of surface operations only</u> – gas drainage costs are assumed to be sunk costs already incurred by the mine for safety reasons.**

VAM Destruction and Use

Technology	Capex	Opex
Regenerative Thermal Oxidizer (RTO)	$50K-$75K per m^3/s throughput installed (eg. 60 m^3/s unit = $3-4.5 million)	60% of lifecycle project costs for a 10-year project (for 60 m^3/s unit, opex = $675K/yr)

Generating 1 kWh electricity need to consume 0.077kg CH_4 (equal to 1.925kg CO_2)

Over 200 CMM/VAM projects operational around the world



Power generation	**709 MW of generation capacity**
Gas sales	**2,716 million m^3 per year**
Annual Emission Reductions	**29.4 million tonnes CO_2 equivalent**

4.2. Real reduction ability analysis of Mining-Potash

Table 60. Real reduction ability of Mining-Potash industry

Category	Rate of mitigation
Emission reduction potential of fuels	
Fuels to produce steam	70%-80%
Transportation	20%-25%
Emission reduction potential of evaporative crystallization	
Forced circulation evaporator	25%-50%
DTB crystallizer	30%-40%

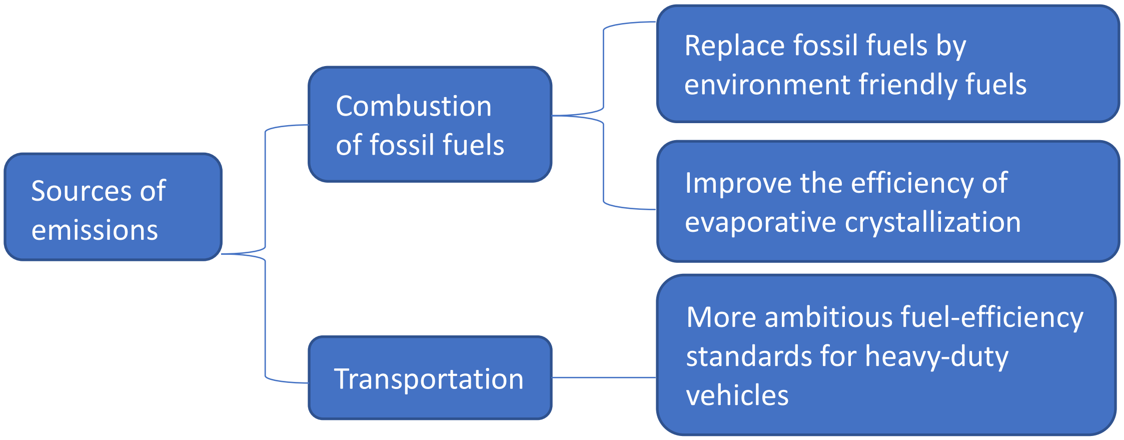


Figure 18. Overview of GHG emission reduction of Potash industry

The direct greenhouse gas emissions from Potash operations result primarily from two sources. The most significant one is combustion of fossil fuels to produce steam and dry potash products at potash solution mine. To a lesser extent, at potash shaft mines, natural gas is used as a fuel to heat fresh air supplied to the shaft mines and for drying potash products. In addition, the production of energy and raw materials that the Potash production companies purchase from unrelated parties for use in business and energy used in the transportation of the products and raw materials are sources of greenhouse gas emissions.

Governmental greenhouse gas emission initiatives include, among others, the December 2015 agreement (the “Paris Agreement”) which was the outcome of the 21st session of the Conference of the Parties under the United Nations Framework Convention on Climate Change (“UNFCCC”). The Paris Agreement, which was signed by nearly 200 nations including the United States and Canada, entered into force in late 2016 and sets out a goal of limiting the average rise in temperatures for this century to below 2 degrees Celsius. Each signatory is expected to develop its own plan (referred to as a Nationally Determined Contribution, or “NDC”) for reaching that goal.

The NDC submitted by the United States aims to achieve, by 2025, an economy-wide target of reducing greenhouse gas emissions by 26-28% below its 2005 level. It also aims to use best efforts to reduce its emissions by 28%. The U.S. target covers all greenhouse gases that were a part of the 2014 Inventory of Greenhouse Gas Emissions and Sinks. While it is unclear whether the new U.S. executive administration will seek to implement the U.S. NDC, various legislative or regulatory initiatives relating to greenhouse gases have been adopted or considered by the U.S. Congress, EPA or various states and those initiatives already adopted may be used to implement the U.S. NDC. Additionally, more stringent laws and regulations may be enacted to accomplish the goals set out in the NDC.

Canada’s intended NDC aims to achieve, by 2030, an economy-wide target of reducing greenhouse gas emissions by 30% below 2005 levels. In addition, in late 2016 the federal government announced plans for a comprehensive tax on carbon emissions, under which provinces opting out of the tax would have the option of adopting a cap-and-trade system. While no tax has formally been proposed, as implementation of the Paris Agreement proceeds, more stringent laws and regulations may be enacted to accomplish the goals set out in Canada's NDC. In addition, the Province of Saskatchewan has passed legislation to facilitate the development and administration of climate change regulation in Saskatchewan by the Province rather than the federal government. This legislation is not yet effective, but key elements under consideration by the Province include establishing a provincial greenhouse gas emission reduction target, and compliance mechanisms that would provide flexibility for regulated emitters to meet their greenhouse gas reduction obligations.

It is possible that future legislation or regulation addressing climate change, including in response to the Paris Agreement or any new international agreements, could adversely affect the Potash related companies' operating activities, energy, raw material and transportation costs, results of operations, liquidity or capital resources, and these effects could be material.

Thus, it is highly necessary for the Potash industry to figure out the most effective way to reduce greenhouse gas emissions.

For the first source of emissions, there are two breakthrough points. On the one hand, we can replace the fossil fuels by other environment friendly fuels, such as nuclear power. Small module reactors (SMRs) is a good choice. SMRs are a type of nuclear fission reactor which are smaller than conventional reactors and manufactured at a plant and brought to a site to be fully constructed. Small reactors are defined by the International Atomic Energy Agency as those with an electricity output of less than 300 MW. Modular reactors allow for less on-site construction, increased containment efficiency, and heightened nuclear materials security. SMRs have been considered to be less expensive than traditional nuclear reactors.

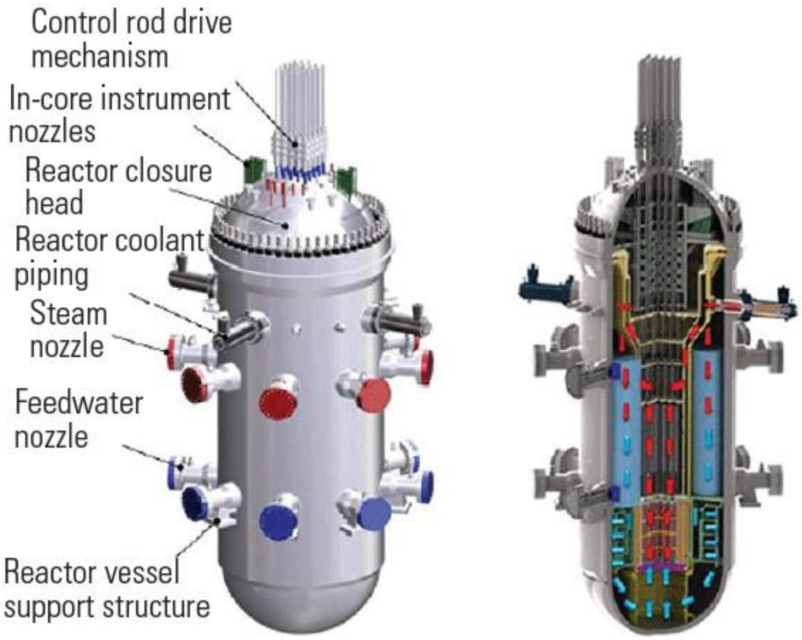


Figure 19. Small module reactors

SMRs could be used to power significant users of energy, such as large vessels or production facilities (e.g. water treatment/purification, or mines). Remote locations often have difficulty finding economically efficient, reliable energy sources. Small nuclear reactors have been considered as solutions to many energy problems in these hard-to-reach places. Cogeneration options have been presented in journals.

Traditionally, nuclear reactors use a coolant loop to heat water into steam, and use that steam to run turbines to generate electricity. There are some of the new gas-cooled reactor designs that are meant to drive a gas-powered turbine, rather than using a secondary water system. Also, there are some plants now that are used for their ability to generate thermal, rather than electric, energy. Nuclear reactor heat can be used in hydrogen production and myriad commercial operations. Right now, some of the possible nuclear heat applications include water desalination, heat for the production of petroleum products (extracting oil from tar sands, creating synthetic oil from coal, etc.), and the production of hydrogen for use in anything from car batteries to nitrogen fertilizers. Therefore, it is to generate thermal by using SMRs.

There are numerous new reactor designs being generated all over the world. A small selection of the current SMR designs is listed below.

Table 61. List of small nuclear reactor designs

Name	Gross power (MWe)	Type	Producer	Status
Xe-100	35	HTGR	X-energy, USA	Conceptual design development
IRIS	335	PWR	Westinghouse-led, international	Basic Design
Westinghouse SMR	225	PWR	Westinghouse Electric Company, USA	Preliminary Design Completed
U-Battery	4	PBR	U-Battery consortium, UK	Conceptual Design
4S	10–50	FNR	Toshiba, Japan	Detailed Design
IMSR400	185–192	MSR	Terrestrial Energy, Inc.,[38] Canada	Conceptual Design
ABV-6	6–9	PWR	OKBM Afrikantov, Russia	Detailed Design
GT-MHR	285	HTGR	OKBM Afrikantov, Russia	Conceptual Design Completed
KLT-40S	35	PWR	OKBM Afrikantov, Russia	Under Construction
MHR-100	25–87	HTGR	OKBM Afrikantov, Russia	Conceptual Design
MHR-T	4x205.5	HTGR	OKBM Afrikantov, Russia	Conceptual Design
RITM-200	50	PWR	OKBM Afrikantov, Russia	Under Construction
VBER-300	325	PWR	OKBM Afrikantov, Russia	Licensing Stage
ANGSTREM	6	LFR	OKB Gidropress, Russia	Conceptual Design
SVBR-100	100	LFR	OKB Gidropress, Russia	Detailed Design
VVER-300	300	BWR	OKB Gidropress, Russia	Conceptual Design
NuScale	45–50	LWR	NuScale Power LLC, USA	Licensing Stage
SSR	37.5x8	MSR	Moltex Energy LLP,[41] UK	Conceptual Design
ELENA	0.068	PWR	Kurchatov Institute, Russia	Conceptual Design
SMART	100	PWR	KAERI, S. Korea	Licensed
MRX	30–100	PWR	JAERI, Japan	Conceptual Design
EGP-6	11	RBMK	IPPE & Teploelektroproekt Design, Russia	Operating
Fuji MSR	200	MSR	International Thorium Molten Salt Forum, Japan	Conceptual Design
TerraPower	10	TWR	Intellectual Ventures - Bellevue, WA USA	Conceptual Design
SMR-160	160	PWR	Holtec International, USA	Conceptual Design
G4M	25	LFR	Gen4 Energy, USA	Conceptual Design
S-PRISM	311	FBR	GE Hitachi Nuclear Energy	Detailed Design
PBMR-400	165	HTGR	Eskom, South Africa, et al.	Detailed Design
CAREM	27–30	PWR	CNEA & INVAP, Argentina	Under Construction
mPower	195	PWR	Babcock & Wilcox, USA	Cancelled March 2017
VK-300	250	BWR	Atomstroyexport, Russia	Detailed Design
BREST-OD-300	300	LFR	Atomenergoprom, Russia	Detailed Design
NP-300	100–300	PWR	Areva TA, France	Conceptual Design
Flexblue	160	PWR	Areva TA / DCNS group, France	Conceptual Design

On the other hand, we can improve the efficiency of evaporative crystallization. Crystallization is the (natural or artificial) process by which a solid form, where the atoms or molecules are highly organized into a structure known as a crystal. Some of the ways by which crystals form are precipitating from a solution, melting, or more rarely deposition directly from a gas. Attributes of the resulting crystal depend largely on factors such as temperature, air pressure, and in the case of liquid crystals, time of fluid evaporation.

Crystallization occurs in two major steps. The first is nucleation, the appearance of a crystalline phase from either a supercooled liquid or a supersaturated solvent. The second step is known as crystal growth, which is the increase in the size of particles and leads to a crystal state. An important feature of this step is that loose particles form layers at the crystal's surface lodge themselves into open inconsistencies such as pores, cracks, etc.

The majority of minerals and organic molecules crystallize easily, and the resulting crystals are generally of good quality, i.e. without visible defects. However, larger biochemical particles, like proteins, are often difficult to crystallize. The ease with which molecules will crystallize strongly depends on the intensity of either atomic forces (in the case of mineral substances), intermolecular forces (organic and biochemical substances) or intramolecular forces (biochemical substances).

Crystallization is also a chemical solid–liquid separation technique, in which mass transfer of a solute from the liquid solution to a pure solid crystalline phase occurs. In chemical engineering, crystallization occurs in a crystallizer. Crystallization is therefore related to precipitation, although the result is not amorphous or disordered, but a crystal. Some of the important factors influencing solubility are:

- Concentration
- Temperature
- Polarity
- Ionic strength

So, one may identify two main families of crystallization processes:

- Cooling crystallization
- Evaporative crystallization

This division is not really clear-cut, since hybrid systems exist, where cooling is performed through evaporation, thus obtaining at the same time a concentration of the solution. A crystallization process often referred to in chemical engineering is the fractional crystallization. This is not a different process, rather a special application of one (or both) of the above.

Thus, try to improve the efficiency of evaporative crystallization is a possible way to reduce energy consumption, and therefore reduce the greenhouse gas emissions.

Most industrial crystallizers are of the evaporative type, such as the very large sodium chloride and sucrose units, whose production accounts for more than 50% of the total world production of crystals. The most common type is the forced circulation (FC) model (see evaporator). A pumping device (a pump or an axial flow mixer) keeps the crystal slurry in homogeneous suspension throughout the tank, including the exchange surfaces; by controlling pump flow, control of the contact time of the crystal mass with the supersaturated solution is achieved, together with reasonable velocities at the exchange surfaces. The Oslo, mentioned above, is a refining of the evaporative forced circulation crystallizer, now equipped with large crystals settling zone to increase the retention time (usually low in the FC) and to roughly separate heavy slurry zones from clear liquid. Evaporative crystallizers tend to yield larger average crystal size and narrows the crystal size distribution curve.

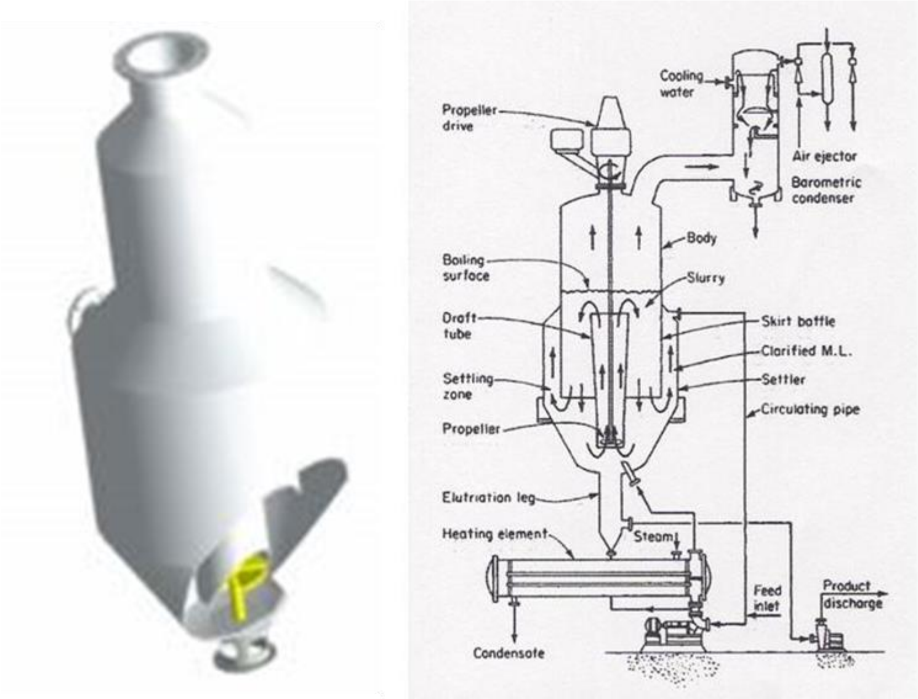


Figure 20. DTB crystallizer

Whichever the form of the crystallizer, to achieve an effective process control it is important to control the retention time and the crystal mass, to obtain the optimum conditions in terms of crystal specific surface and the fastest possible growth. This is achieved by a separation – to put it simply – of the crystals from the liquid mass, in order to manage the two flows in a different way. The practical way is to perform a gravity settling to be able to extract (and possibly recycle separately) the (almost) clear liquid, while managing the mass flow around the crystallizer to obtain a precise slurry density elsewhere. A typical example is the DTB (Draft Tube and Baffle) crystallizer, an idea of Richard Chisum Bennett (a Swenson engineer and later President of Swenson) at the end of the 1950s. The DTB crystallizer (see images) has an internal circulator, typically an axial flow mixer – yellow – pushing upwards in a draft tube while outside the crystallizer there is a settling area in an annulus; in it the exhaust solution moves upwards at a very low velocity, so that large crystals settle – and return to the main circulation – while only the fines, below a given grain size are extracted and eventually destroyed by increasing or decreasing temperature, thus creating additional supersaturation. A quasi-perfect control of all parameters is achieved as DTF crystallizers offer superior control over crystal size and characteristics. This crystallizer, and the derivative models (Krystal, CSC, etc.) could be the ultimate solution if not for a major limitation in the evaporative capacity, due to the limited diameter of the vapour head and the relatively low external circulation not allowing large amounts of energy to be supplied to the system.

Another effective way to improve the efficiency of evaporative crystallization is to introduce circulation evaporator technology. Circulation evaporators are a type of evaporating unit designed to separate mixtures unable to be evaporated by a conventional evaporating unit. Circulation evaporation incorporates the use of both heat exchangers and flash separation units in conjunction with circulation of the solvent in order to remove liquid mixtures without conventional boiling.

There are two types of Circulation Evaporation; Natural Circulation Evaporators and Forced Circulation Evaporators, both of which are still currently used in industry today.

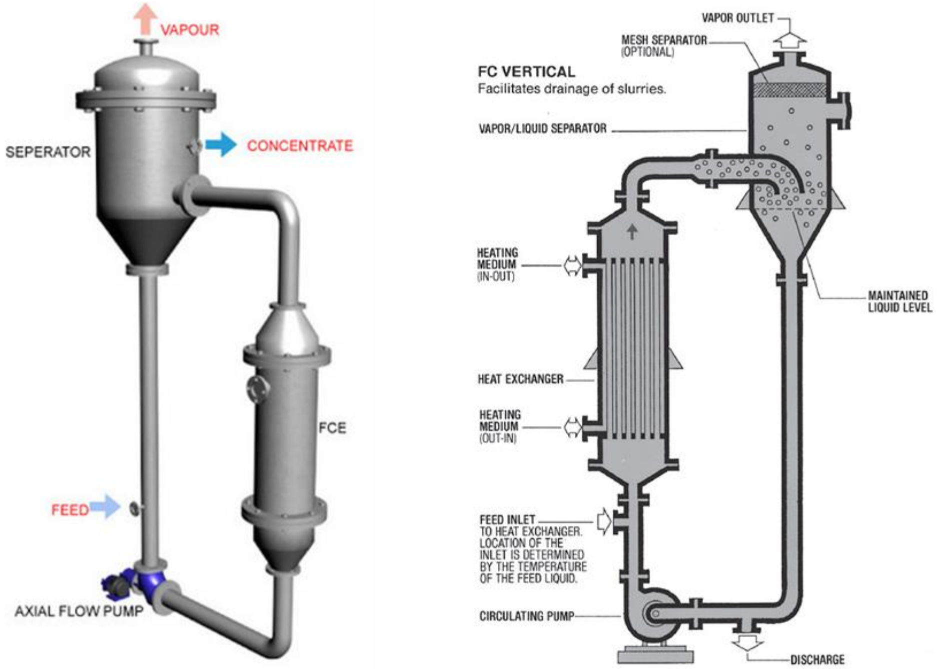


Figure 21. Forced circulation evaporator

Evaporators are designed with two key objectives: Is the equipment to be selected best suited for the duty, and is the arrangement the most efficient and economical. Heat transfer greatly affects evaporator design, as it represents the greatest cost in its operation. The most suitable evaporator will have the highest heat transfer coefficient per dollar of equipment cost. In optimising the design of an evaporator, another important consideration is the steam economy (kg of solvent evaporated per kilogram of steam used). The best way to achieve high economies (which can be well over 100%) is to use multiple effect evaporator, whereby the vapour from one evaporator – or effect – is used to heat the feed in the next effect, where boiling occurs at lower pressure and temperature. Thermo-compression of the vapour, whereby the vapour will condense at a temperature high enough to be reused for the next effect through compression, will also increase efficiency. However, increased energy efficiency can only be achieved through higher capital costs and a general rule is the larger the system, the more it will pay back to increase the thermal efficiency of the evaporator.

Heat transfer is not the sole design criteria however, as the most appropriate evaporator also depends on properties of the feed and products. Crystallisation, salting and scaling, product quality and its heat sensitivity, foaming potential of the solution, viscosity of feed (which increases with evaporation) and its nature (slurry or concentrate) all need to be considered. For Single Effect Evaporators that are used in small scale processes with low throughput of material, material and energy balances can be used to design and optimise the process. In designing multiple effect evaporators, trial and error methods with many iterations are usually the fastest and most efficient.

As mentioned above, transportation is another source of greenhouse gas emissions during the production process of Potash. Transportation includes electric conveyor belt, and transport by truck, rail and ship. This is a section whose emissions often be ignored. However, in fact, the transportation sector is currently responsible for 23% of Canada's GHG emissions and offers tremendous opportunities for significant emissions reduction. To reduce emissions in the transportation sector, Canada needs to drive a transition towards zero and low-emissions transportation modes, increase the use of cleaner fuels in Canada, increase public transit ridership, and encourage denser, mixed-use communities.

It is worth mentioning that heavy-duty trucking is the fastest growing sub-sector of transportation emissions and between 1990 and 2014, freight accounted for almost 60% of the total 55 MT increase in emissions from the transport sector. Incentives to switch to lower emissions modes of transportation for heavy-freight and policies to reduce the emissions intensity of freight are critical to tackle this significant contributor to emissions.

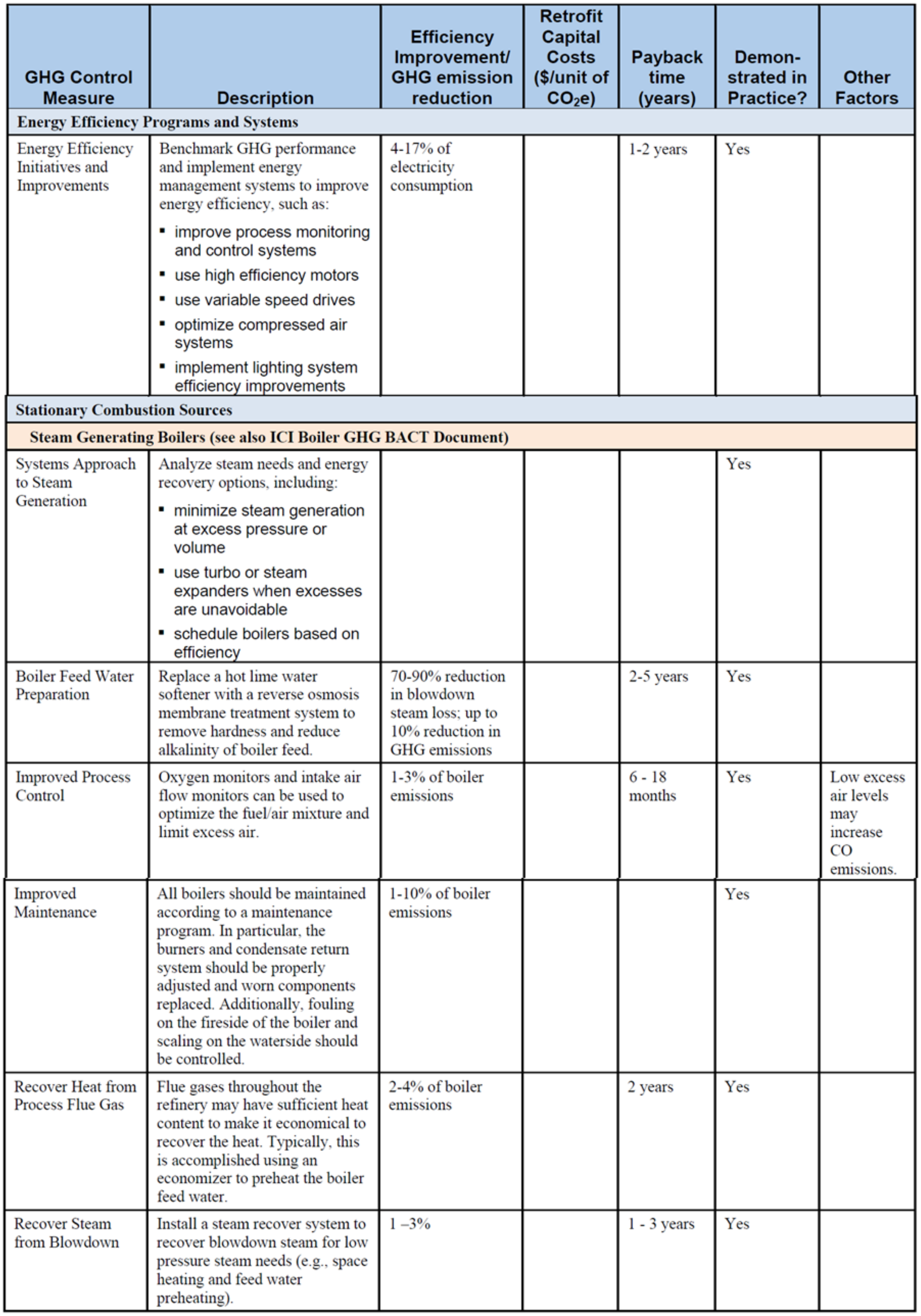
There is a policy goal that by 2025, reduce GHG emissions from the light and heavy freight sector in Canada by 40% through new stringent GHG emission regulations for light and heavy-duty trucks, incentives for mode switching to lower carbon transportation modes and increased use of biodiesel. It is crucial to put strong standards in place now since heavy-duty trucks are the fastest-growing single source of GHG emissions in the transportation sector; In the recent U.S.-Canada Joint Statement on Climate, Energy and Arctic Leadership, Canada and the U.S. committed to continue to establish world-class, aligned regulations and programs to improve the fuel efficiency and reduce GHG and air pollutant emissions from on-road vehicles. This includes the finalization and implementation of a second phase of aligned GHG emission standards for post-2018 models of on-road heavy-duty vehicles and to accelerate the improvement of vehicle efficiency and zero emission technologies. Representatives of the trucking industry believe a 40% reduction in fuel consumption by 2025—a stronger standard than what has been initially proposed by the Environmental Protection Agency – is technologically feasible and would yield even greater economic and environmental benefits. More ambitious fuel-efficiency standards for cars, adopted in 2010, have driven investments in the development and manufacturing of far more fuel-efficient vehicles. Similarly, stringent regulations are required to drive innovation in the manufacturing of new trucks. Without long-term standards in place to level the playing field, truck manufacturers find it much harder to commit to the multi-year investment of bringing fuel-efficient technologies to market.

To achieve that policy goal, several recommendations are proposed:

- Provide R&D investments to spur innovation in technologies to reduce GHG emissions in the heavy-freight sector, including infrastructure and incentives for mode switching to lower emitting transportation (e.g. rail);
- Establish stringent GHG emission regulations for heavy freight for post-2018 models;
- Provide financial incentives and improve infrastructure (e.g. charging stations) for the electrification of light-freight (i.e. short distance delivery trucks);
- Provide incentives for the adoption of renewable biodiesel as a transition fuel for the heavy-freight sector.

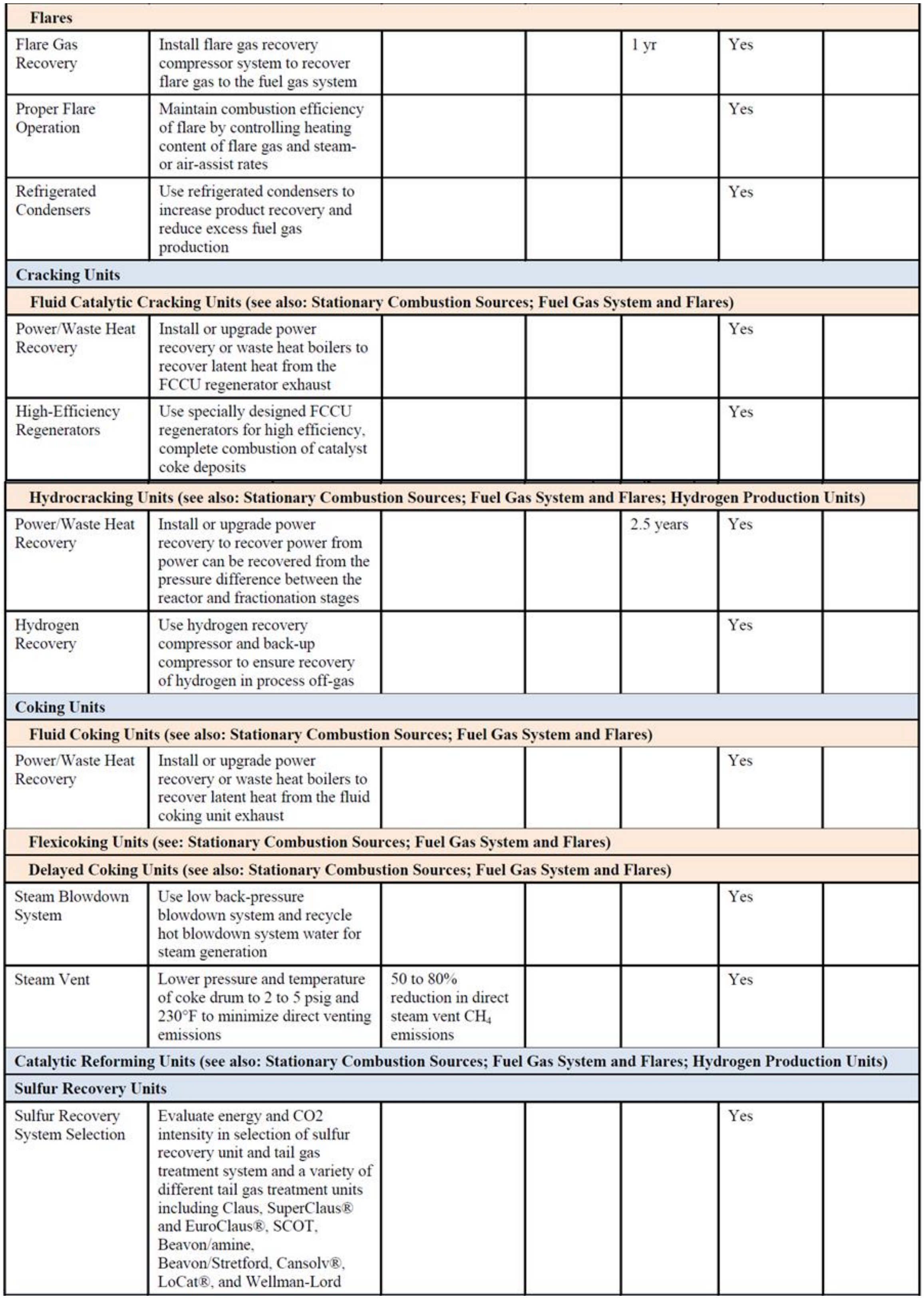
4.3. Real reduction ability analysis of Petroleum Refinery

Table 62. Real reduction ability of Petroleum Refinery industry



GHG Control Measure	Description	Efficiency Improvement/ GHG emission reduction	Retrofit Capital Costs ($/unit of CO_2e)	Payback time (years)	Demon-strated in Practice?	Other Factors
Energy Efficiency Programs and Systems						
Energy Efficiency Initiatives and Improvements	Benchmark GHG performance and implement energy management systems to improve energy efficiency, such as: ▪ improve process monitoring and control systems ▪ use high efficiency motors ▪ use variable speed drives ▪ optimize compressed air systems ▪ implement lighting system efficiency improvements	4-17% of electricity consumption		1-2 years	Yes	
Stationary Combustion Sources						
Steam Generating Boilers (see also ICI Boiler GHG BACT Document)						
Systems Approach to Steam Generation	Analyze steam needs and energy recovery options, including: ▪ minimize steam generation at excess pressure or volume ▪ use turbo or steam expanders when excesses are unavoidable ▪ schedule boilers based on efficiency				Yes	
Boiler Feed Water Preparation	Replace a hot lime water softener with a reverse osmosis membrane treatment system to remove hardness and reduce alkalinity of boiler feed.	70-90% reduction in blowdown steam loss; up to 10% reduction in GHG emissions		2-5 years	Yes	
Improved Process Control	Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and limit excess air.	1-3% of boiler emissions		6 - 18 months	Yes	Low excess air levels may increase CO emissions.
Improved Maintenance	All boilers should be maintained according to a maintenance program. In particular, the burners and condensate return system should be properly adjusted and worn components replaced. Additionally, fouling on the fireside of the boiler and scaling on the waterside should be controlled.	1-10% of boiler emissions			Yes	
Recover Heat from Process Flue Gas	Flue gases throughout the refinery may have sufficient heat content to make it economical to recover the heat. Typically, this is accomplished using an economizer to preheat the boiler feed water.	2-4% of boiler emissions		2 years	Yes	
Recover Steam from Blowdown	Install a steam recover system to recover blowdown steam for low pressure steam needs (e.g., space heating and feed water preheating).	1 –3%		1 - 3 years	Yes	

Reduce Standby Losses	Reduce or eliminate steam production at standby by modifying the burner, combustion air supply, and boiler feedwater supply, and using automatic control systems to reduce the time needed to reach full boiler capacity.	Up to 85% reduction in standby losses (but likely a small fraction of facility total boiler emissions)		1.5 years	Yes	
Improve and Maintain Steam Traps	Implement a maintenance plan that includes regular inspection and maintenance of steam traps to prevent steam lost through malfunctioning steam traps.	1-10% of boiler emissions			Yes	
Install Steam Condensate Return Lines	Reuse of the steam condensate reduces the amount of feed water needed and reduces the amount of energy needed to produce steam since the condensate is preheated.	1- 10% of steam energy use		1-2 years	Yes	
Process Heaters						
Combustion Air Controls- Limitations on Excess air	Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and limit excess air.	1-3%		6-18 months	Yes	
Heat Recovery: Air Preheater	Air preheater package consists of a compact air-to-air heat exchanger installed at grade level through which the hot stack gases from the convective section exchange heat with the incoming combustion air. If the original heater is natural draft, a retrofit requires conversion to mechanical draft.	10-15% over units with no preheat.			Yes	**May increase NOx emissions**
Combined Heat and Power						
Combined Heat and Power	Use internally generated fuels or natural gas for power (electricity) production using a gas turbine and generate steam from waste heat of combustion exhaust to achieve greater energy efficiencies			5 years	Yes	
Carbon Capture						
Oxy-combustion	Use pure oxygen in large combustion sources to reduce flue gas volumes and increase CO_2 concentrations to improve capture efficiency and costs				No	
Post-combustion Solvent Capture	Use solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, for separation of CO_2 in post-combustion exhaust streams				Yes	
Post-combustion membranes	Use membrane technology to separate or adsorb CO2 in an exhaust stream		$55-63		No	
Fuel Gas System and Flares						
Fuel Gas System						
Compressor Selection	Use dry seal rather than wet seal compressors; use rod packing for reciprocating compressors				Yes	



Flares						
Flare Gas Recovery	Install flare gas recovery compressor system to recover flare gas to the fuel gas system			1 yr	Yes	
Proper Flare Operation	Maintain combustion efficiency of flare by controlling heating content of flare gas and steam- or air-assist rates				Yes	
Refrigerated Condensers	Use refrigerated condensers to increase product recovery and reduce excess fuel gas production				Yes	
Cracking Units						
Fluid Catalytic Cracking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares)						
Power/Waste Heat Recovery	Install or upgrade power recovery or waste heat boilers to recover latent heat from the FCCU regenerator exhaust				Yes	
High-Efficiency Regenerators	Use specially designed FCCU regenerators for high efficiency, complete combustion of catalyst coke deposits				Yes	
Hydrocracking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares; Hydrogen Production Units)						
Power/Waste Heat Recovery	Install or upgrade power recovery to recover power from power can be recovered from the pressure difference between the reactor and fractionation stages			2.5 years	Yes	
Hydrogen Recovery	Use hydrogen recovery compressor and back-up compressor to ensure recovery of hydrogen in process off-gas				Yes	
Coking Units						
Fluid Coking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares)						
Power/Waste Heat Recovery	Install or upgrade power recovery or waste heat boilers to recover latent heat from the fluid coking unit exhaust				Yes	
Flexicoking Units (see: Stationary Combustion Sources; Fuel Gas System and Flares)						
Delayed Coking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares)						
Steam Blowdown System	Use low back-pressure blowdown system and recycle hot blowdown system water for steam generation				Yes	
Steam Vent	Lower pressure and temperature of coke drum to 2 to 5 psig and 230°F to minimize direct venting emissions	50 to 80% reduction in direct steam vent CH_4 emissions			Yes	
Catalytic Reforming Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares; Hydrogen Production Units)						
Sulfur Recovery Units						
Sulfur Recovery System Selection	Evaluate energy and CO2 intensity in selection of sulfur recovery unit and tail gas treatment system and a variety of different tail gas treatment units including Claus, SuperClaus® and EuroClaus®, SCOT, Beavon/amine, Beavon/Stretford, Cansolv®, LoCat®, and Wellman-Lord				Yes	

Hydrotreating Units (see also: Hydrogen Production Units; Sulfur Recovery Units)						
Hydrotreater Design	Use energy efficient hydrotreater designs and new catalyst to increase sulfur removal.				Yes	
Crude Desalting and Distillation Units						
Desalter Design	Alternative designs for the desalter, such as multi-stage units and combinations of AC and DC fields, may increase efficiency and reduce energy consumption.				Yes	
Progressive Distillation Design	Progressive distillation process uses as series of distillation towers working at different temperatures to avoid superheating lighter fractions of the crude oil.	30% reduction in crude heater emissions; 5% or more refinery-wide			Yes	
Hydrogen Production Units						
Hydrogen Production Optimization	Implement a comprehensive assessment of hydrogen needs and consider using additional catalytic reforming units to produce H_2				Yes	
Combustion Air and Feed/Steam Preheat	Use heat recovery systems to preheat the feed/steam and combustion air temperature	5% of total energy consumption for H_2 production			Yes	
Storage Tanks						
Vapor Recovery or Control for Unstabilized Crude Oil Tanks	Consider use of a vapor recovery or control system for crude oil storage tanks that receive crude oil that has been stored under pressure ("unstabilized" crude oil)	90-95% reduction in CH_4 from these tanks			Yes	
Heated Storage Tank Insulation	Insulate heated storage tanks				Yes	

4.3.1 Overview of Petroleum Refining Industry

Petroleum refineries produce liquefied petroleum gases (LPG), motor gasoline, jet fuels, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen), and other products through distillation of crude oil or through redistillation, cracking, or reforming of unfinished petroleum derivatives. There are three basic types of refineries: topping refineries, hydroskimming refineries, and upgrading refineries (also referred to as "conversion" or "complex" refineries). Topping refineries have a crude distillation column and produce naphtha and other intermediate products, but not gasoline. There are only a few topping refineries in the U.S., predominately in Alaska. Hydroskimming refineries have mild conversion units such as hydrotreating units and/or reforming units to produce finished gasoline products, but they do not upgrade heavier components of the crude oil that exit near the bottom of the crude distillation column. Some topping/hydroskimming refineries specialize in processing heavy crude oils to produce asphalt. There are eight operating asphalt plants and approximately 20 other 2 hydroskimming refineries operating in the United States as of January 2006 (Energy Information Administration [EIA], 2006). The vast majority (approximately 75 to 80 percent) of the approximately 150 domestic refineries are upgrading/conversion refineries. Upgrading/conversion refineries have cracking or coking operations to convert long-chain, high molecular weight hydrocarbons ("heavy distillates") into smaller hydrocarbons that can be used to produce gasoline product ("light distillates") and other higher value products and petrochemical feedstocks.

Figure 22 provides a simplified flow diagram of a typical refinery. The flow of intermediates between the processes will vary by refinery, and depends on the structure of the refinery, type of crude processes, as well as product mix. The first process unit in nearly all refineries is the crude oil or “atmospheric” distillation unit (CDU). Different conversion processes are available using thermal or catalytic processes, *e.g.*, delayed coking, catalytic cracking, or catalytic reforming, to produce the desired mix of products from the crude oil. The products may be treated to upgrade the product quality (*e.g.*, sulfur removal using a hydrotreater). Side processes that are used to condition inputs or produce hydrogen or byproducts include crude conditioning (*e.g.*, desalting), hydrogen production, power and steam production, and asphalt production. Lubricants and other specialized products may be produced at special locations. More detailed descriptions of petroleum refining processes are available in other locations.

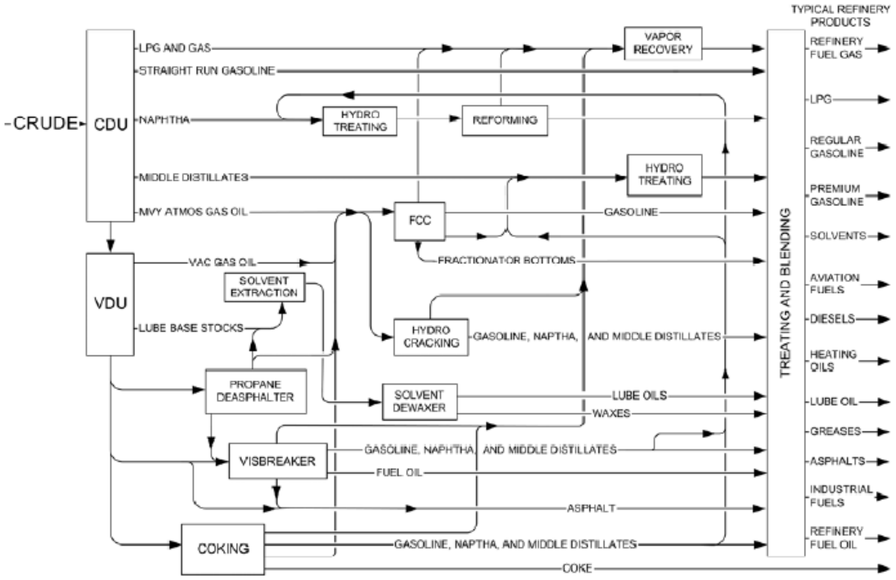


Figure 22. Simplified flowchart of refining processes and product flows.

4.3.2 Petroleum Refining GHG Emission Sources

The petroleum refining industry is the nation’s second-highest industrial consumer of energy. Nearly all of the energy consumed is fossil fuel for combustion; therefore, the petroleum refining industry is a significant source of GHG emissions. In addition to the combustion-related sources (*e.g.*, process heaters and boilers), there are certain processes, such as fluid catalytic cracking units (FCCU), hydrogen production units, and sulfur recovery plants, which have significant process emissions of CO_2. Methane emissions from a typical petroleum refinery arise from process equipment leaks, crude oil storage tanks, asphalt blowing, delayed coking units, and blow down systems. Asphalt blowing and flaring of waste gas also contributes to the overall CO_2 and CH4 emissions at the refinery. Based on a bottom-up, refinery-specific analysis, GHG emissions from petroleum refineries were estimated to be 214-million metric tons of CO_2 equivalents (CO_2e), based on production rates in 2005. Figure 23 provides a breakdown of the nationwide emissions projected for different parts of the petroleum refineries based on this bottom-up analysis.

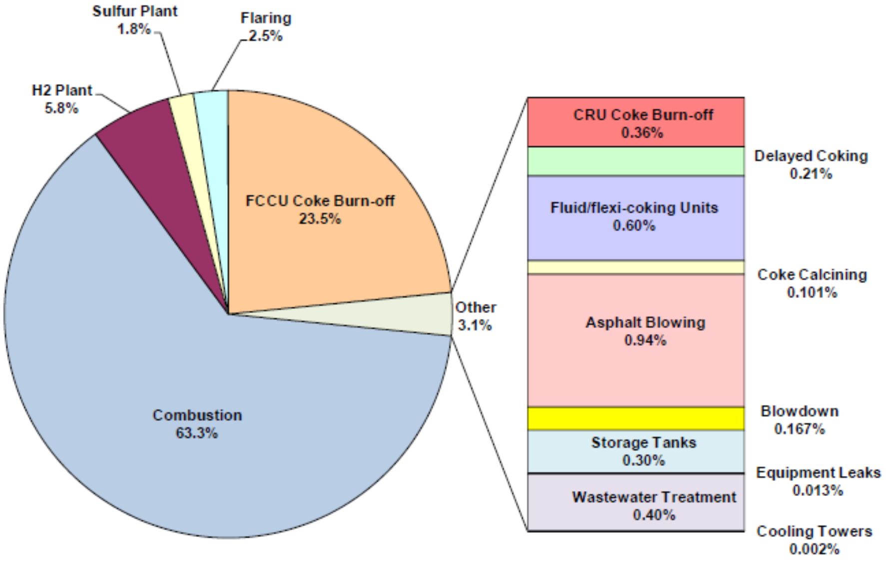


Figure 23. Contribution of different emission sources to the nationwide CO_2 equivalent GHG emissions from petroleum refineries

4.3.3 GHG Reduction Measures

Stationary Combustion Sources

Steam Generating Boilers

According to Worrell and Galitsky (2005), approximately 30 percent of onsite energy use at domestic refineries is used in the form of steam generated by boilers, cogeneration, or waste heat recovery from process unit. However, off-site purchases of steam represent only 3 to 5 percent of the total energy consumption at petroleum refineries nationwide. Given that steam accounts for 30 to 38 percent of a refinery's energy needs, it is evident that most refineries produce their own steam. As such, steam generation and distribution makes a significant contribution to a petroleum refinery's energy needs, and subsequently its on-site GHG emissions.

(1) Systems Approach to Steam Generation

A thorough analysis of steam needs and energy recovery opportunities could be conducted to make the steam generation process as efficient as possible. For example, the analysis should assure that steam is not generated at pressures or volumes larger than what is needed. In those situations where the steam generation has limited adjustability, the excess energy in the steam should be recovered using a turbo expander or steam expansion turbine. Another option is to operate multiple boilers that are regulated according to steam demands. One refinery that implemented a program including scheduling of boilers on the basis of efficiency and minimizing losses in the turbines resulted in $5.4 million in energy savings.

(2) Boiler Feed Water Preparation

Boiler feed water is typically pre-treated to remove contaminates that foul the boiler. A refinery in Utah replaced a hot lime water softener with a reverse osmosis membrane treatment system to remove hardness and reduce alkalinity. Blowdown was reduced from 13.3 percent to 1.5 percent of steam produced. Additionally, reductions were seen in chemical usage, maintenance, and waste disposal costs. The initial investment of the membrane system was $350,000 and annual savings of $200,000 were realized.

(3) Improved Process Control

Boilers are operated with a certain amount of excess air to reduce emissions and for safety considerations. However, too much excess air may lead to inefficient combustion, and energy must be used to heat the excess air. Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture. Payback for such systems is typically about 0.6 years.

(4) Improved Insulation

The insulation of older boilers may be in poor condition, and the material itself may not insulate as well as newer materials. Replacing the insulation combined with improved controls can reduce energy requirements by 6-26 percent. Insulation on steam distribution systems should also be evaluated. Improving the insulation on the distribution pipes at existing facilities may reduce energy usage by 3-13 percent, with an average payback period of 1.1 years.

(5) Improved Maintenance

All boilers should be maintained according to a maintenance program. In particular, the burners and condensate return system should be properly adjusted and worn components replaced. Average energy savings of about 10 percent can be realized over a system without regular maintenance. Additionally, fouling on the fireside of the boiler and scaling on the waterside should be controlled.

(6) Recover Heat from Boiler Flue Gas

Flue gasses throughout the refinery may have sufficient heat content to make it economical to recover the heat. Typically, this is accomplished using an economizer to preheat the boiler feed water. One percent of fuel use can be saved for every 25 °C reduction in flue gas temperature. In some situations, the payback for installing an economizer is about 2 years.

(7) Recover Steam from Blowdown

The pressure drop during blowdown may produce substantial quantities of low grade steam that is suitable for space heating and feed water preheating. For boilers below 100 MMBtu/yr, fuel use can be reduced by about 1.3 percent, and payback may range from 1-2.7 years. A chemical plant installed a steam recover system to recover all of the blowdown steam from one process and realized energy savings of 2.8 percent.

(8) Reduce Standby Losses

It is common practice at most refineries to maintain at least one boiler on standby for emergency use. Steam production at standby can be virtually eliminated by modifying the burner, combustion air supply, and boiler feed water supply. Additionally, automatic control systems can reduce the time needed to reach full capacity of the boiler to a few minutes. These measures can reduce the energy consumption of the standby boiler by as much as 85 percent. These measures were applied to a small 40 tonnes/hr steam boiler at an ammonia plant, resulting in energy savings of 54 TBtu/yr with a capital investment of about $270,000 (1999$). The payback period was 1.5 years.

(9) Improve and Maintain Steam Traps

Significant amounts of steam may be lost through malfunctioning steam traps. A maintenance plan that includes regular inspection and maintenance can reduce boiler energy usage by up to 10 percent.

(10) Install Steam Condensate Return Lines

Reuse of the steam condensate reduces the amount of feed water needed and reduces the amount of energy needed to produce steam since the condensate is preheated. The costs savings can justify the cost of the condensate return lines. Estimates of energy savings are as high as 10 percent, with a payback period of 1.1 years for facilities with no or insufficient condensate return systems.

Process Heaters

(1) Draft Control

Excessive combustion air reduces the efficiency of process heater burners. At one domestic refinery, a control system was installed on three CDU furnaces to maintain excess air at 1 percent rather than the previous 3-4 percent. Energy usage of the burners was reduced by 3-6 percent and nitrogen oxide ($NO_{x)}$ emissions were reduced by 10-25 percent. The cost savings due to reduced energy requirements was $ 340,000. Regular maintenance of the draft air intake systems can reduce energy usage and may result in payback periods of about 2 months. Draft control is applicable to new or existing process heaters, and is cost-effective for a wide range of process heaters (20 to 30 MMBtu/hr or greater).

(2) Air Preheating

The flue gases of the furnace can be used to preheat the combustion air. Every 35 °F drop in exit flue gas temperature increases the thermal efficiency of the furnace by 1 percent. The resulting fuel savings can range from 8-18 percent, and may be economically attractive when the flue gas temperature is above 650 °F and the heater size is 50 MMBtu/hr or more. Payback periods are typically on the order of 2.5 years. One refinery in the United Kingdom installed a combustion air preheater on a vacuum distillation unit (VDU) and reduced energy costs by $109,000/yr. The payback period was 2.2 years. Air preheating would require natural draft system to be converted to a forced draft system requiring installation of fans, which would increase electricity consumption and typically increase NO_X emissions. Consequently, several factors, including process heater size and draft type as well as secondary impacts, need to be considered retrofitting existing process heaters. Air preheating is often much more economical and effective when considered in the design of a new process heater.

Combined Heat and Power (CHP)

The large steam requirements for refining operations and the continuous operations make refineries excellent candidates for combined heat and power (CHP) generation. Refineries represent one of the largest industry sources of CHP today with 103 active CHP plants with an electric generation capacity of 14.6 gigawatts (ICF, 2010). Currently, about 60-70 percent of the 137 refineries operating at the beginning of 2010 use CHP (ICF International, 2010; EIA, 2009).

About 75 percent of the refinery CHP capacity comes from natural gas -fired combined cycle power plants consisting of large combustion turbines with heat recovery steam generators (HRSG) producing power and steam. A portion of the steam produced is used to generate more power in back pressure steam turbines. These plants meet the facility steam loads but often produce much more power than is needed by the facility itself, and, therefore, export power to the electric grid. The next most common type of CHP system is a combustion turbine with heat recovery. These systems make up about 11 percent of the existing refinery CHP capacity. Again, these systems are fueled mostly with natural gas, but internally generated fuels (*i.e*., refinery fuel gas) are also used. Most of the remaining system CHP capacity is boilers producing high pressure steam that run through a back-pressure steam turbine to produce power and lower pressure steam for process use. These systems generally do not use natural gas but, instead, are fired with a variety of internally generated fuels, waste fuels, and even coal.

While CHP systems are already in use at the majority of domestic refineries, there are significant remaining opportunities to add CHP-based on evaluation of steam requirements met by boilers and by CHP. In addition, there are opportunities to repower existing CHP plants making them larger and more efficient by adding newer, more efficient combustion turbines and by converting existing simple cycle plants to combined cycle operation by adding steam turbines for additional power. Additionally, as refineries install flare gas recovery systems, they may need to install CHP systems to provide a productive source for utilizing the recovered fuel gas. There may be no direct CO_2 reductions at refineries from this technology, but indirect reductions from displacing grid power. The level of reduction is a function of the CO_2 intensity of the displaced external power production.

CHP systems require a fairly substantial investment ($1,000 -2,500/kilowatt (kW)); however, the economics of CHP operation at refineries is generally very attractive. One refinery installed a 34 megawatt (MW) cogeneration unit in 1990 that consisted of two gas turbines and two heat recovery steam boilers. All facility electricity needs are met by the unit, and occasionally excess electricity is exported to the grid. Cost savings resulting from the onsite production of electricity were about $55,000/day. CHP can also be economical for small refineries. One study for an asphalt refinery showed that a 6.5 MW gas turbine CHP unit would reduce energy costs by $3.8 million/yr with a payback period of 2.5 years.

Carbon Capture

The post-combustion technologies listed below are generally end-of-pipe measures. It should be noted that petroleum refineries emit CO_2 from a number of different process, and the exhaust stacks for these emission points are numerous and scattered across the facility. The consideration of CO_2 capture and control at a refinery would likely be limited to the larger CO_2 emitting stacks, such as the FCCU, the fluid coking unit, the hydrogen plant, and large boilers or process heaters.

(1) Oxy-Combustion

Oxy-combustion is the process of burning a fuel in the presence of pure or nearly pure oxygen instead of air. Fuel requirements are reduced because there is no nitrogen component to be heated, and the resulting flue gas volumes are significantly reduced (Barker, 2009).

The process uses an air separation unit to remove the nitrogen component from air. The oxygen-rich stream is then fed to the combustion unit so the resulting exhaust gas contains a higher concentration of CO_2, as much as 80 percent. A portion of the exhaust stream is discharged to a CO_2 separation, purification, and compression facility. The higher concentration of CO_2 in the flue gas directly impacts size of the absorber (or other separation technique), and the power requirements for CO_2 compression. This technology is still in the research stage. The

Petroleum Environmental Research Forum (PERF) is focusing on large refinery combustion sources, particularly the FCCU and crude oil process heaters.

(2) Post-Combustion Solvent Capture and Stripping

Post-combustion capture using solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, is a commercially mature technology. Solvent scrubbing has been used in the chemical industry for separation of CO_2 in exhaust streams (Bosoaga, 2009).

(3) Post-Combustion Membranes

Membrane technology may be used to separate or adsorb CO_2 in an exhaust stream. It has been estimated that 80 percent of the CO_2 could be captured using this technology. The captured CO_2 would then be purified and compressed for transport. Initial projections of specific costs range from $55-63/tonne CO_2 avoided for cement manufacturing. The current state of this technology is primarily the research stage, with industrial application at least 10 years away. Positive aspects of membrane systems include very low maintenance (no regeneration required) (ECRA, 2009).

Fuel Gas Systems and Flares

Fuel Gas Systems

Many process units at the refinery, particularly atmospheric crude oil distillation, catalytic cracking, catalytic hydrocracking, thermal cracking, and coking processes, produce fuel gas that is commonly recovered for use in process heaters and boilers throughout the refinery. Typically a compressor is needed to recover the fuel gas at the fuel gas producing unit. The fuel gas generally needs to be treated to remove H_2S using amine scrubber systems. The remainder of the fuel gas system consists of piping and mix drums to transport the fuel gas to the various combustion sources at the refinery. Rather than repeating the GHG reduction measures for each potential fuel gas producing units, the GHG reduction measures for the fuel gas system are summarized here.

(1) Compressor Selection

Different types of compressors have different propensities to leak. Based on emission factors for natural gas compressors, reciprocating compressors generally have approximately one-half the fugitive emissions of centrifugal compressors (U.S. EPA, 1999). Rod packing (e.g., Static-Pac) can be used to reduce fugitive emissions from reciprocating compressors, and dry seal centrifugal compressors have lower emissions (i.e., are less likely to leak) than those with wet seals (U.S. EPA, 1999). Thus, the projected methane emissions from fuel gas compressors could be considered in the selection of the type of compressor and fugitive controls used.

(2) Leak Detection and Repair (LDAR)

LDAR programs have been used to reduce emissions of volatile organic compounds (VOC) from petroleum refineries for years. However, CH_4 is not a VOC, so current regulations do not generally require LDAR for refinery fuel gas systems or other high CH_4-containing gas streams. Leaks can be detected using organic vapor analyzers or specially designed cameras. LDAR programs commonly achieve emission reduction efficiencies of 80 to 90 percent; however, CH_4 emissions from leaking equipment components is expected to have a minimal contribution to the refinery's total GHG emissions.

(3) Selection of Fuel Gas Sulfur Scrubbing System

Hydrogen sulfide in fuel gas is commonly removed by amine scrubbing. The scrubbing solution is typically regenerated by heating the scrubbing solution in a stripping column, typically using steam. The regeneration process can use significant energy, and the energy intensity (impacting CO_2 emissions) of the different processes should be considered (in conjunction with the sulfur scrubbing efficiencies) in selecting scrubbing technology. Some fuel gas, such as fuel gas produced by coking units, contain a significant quantity of other reduced sulfur compounds, such as methyl mercaptan and carbon disulfide, that are not removed by conventional amine scrubbing. The impact of these other reduced sulfur compounds on the resulting sulfur dioxide (SO_2) emissions from process heaters and other fuel gas combustion devices using coker-produced fuel gas should be considered for both energy efficiency (for GHG emission reductions) and total sulfur removal efficiency (for SO_2 emission reductions). Alternatives to conventional amine scrubbing (which uses dimethylethylamine, DMEA), include the use of proprietary scrubbing systems, such as FLEXSORB®, Selexol®, and Rectisol®, as well as using a mixture of solvents as in the Sulfinol process, additional conversion of sulfur compounds to H2S prior to scrubbing, or using a direct fuel gas scrubbing/sulfur recovery technology like LoCat® or caustic scrubbers.

CO_2 is also removed by amine scrubbing; however, this will not really impact the CO_2 emissions from the plant unless sulfur recovery occurs offsite because the CO_2 will be emitted either from the combustion unit receiving the fuel gas or from the sulfur recovery unit receiving the sour gas from the amine scrubbers. Therefore, the CO_2 scrubbing efficiency of the amine scrubbers is not important; however, some light hydrocarbons may also dissolve in the amine solution and subsequently sent to the sulfur recovery plant in the sour gas stream. Most hydrocarbons in the sour gas will eventually be oxidized in the sulfur recovery plant, so entrainment of hydrocarbons does lead to additional CO_2 emissions. Therefore, scrubbing systems could be evaluated based on their sulfur removal efficiency, energy efficiency, and ability to not entrain hydrocarbons. Note that higher sulfur removal efficiencies may have an energy penalty (*i.e.*, requiring more regeneration steam per pound of treated fuel gas), so a holistic analysis is needed when selecting the sulfur scrubbing system.

Flares

(1) Flare Gas Recovery

Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks. Such systems have been installed at a number of domestic refineries. At one 65,000 bpd facility in Arkansas, two flare gas recovery systems were installed that reduced flaring almost completely. This facility will use flaring only in emergencies when the amount of flare gas exceeds the capacity of the recovery system. The recovered gas is compressed and used in the refinery's fuel system. The payback period for flare gas recovery systems may be as little as 1 year. Similar flare gas recovery projects have been reported in the literature (John Zinc Co, 2006; Envirocomb Limited, 2006; Peterson et al., 2007; U.S. DOE, 2005), reducing flaring by approximately 95 percent. Based on emission inventory presented by Lucas (2008), nationwide CO_2 emissions from flaring at petroleum refineries were estimated to be 5 million metric tons. Provided that the recovered fuel can off-set natural gas purchases, flare gas recovery is generally cost-effective for recovering routine flows of flare gas exceeding 20 MMBtu/hr (approximately 0.5 to 1-million scf per day, depending on heat content of flare gas). Based on these estimates, flare gas recovery could reduce nationwide CO_2 emissions from flares by 3-million metric tons. The cost- effectiveness of flare gas recovery is highly dependent on the heating value of the flare gas to be recovered and the price of natural gas. For refineries that may have excess fuel gas, a flare gas recovery system may also need to include a combined heat and power unit to productively use the recovered flare gas as described in Section 3.3.3.1.

(2) Proper Flare Operation

Poor flare combustion efficiencies generally lead to higher methane emissions and therefore higher overall GHG emissions due to the higher global warming potential (GWP) of methane. Poor flare combustion efficiencies can occur at very low flare rates with high crosswinds, at very high flow rates (*i.e.*, high flare exit velocities), when flaring gas with low heat content, and excessive steam- to-gas mass flows. Installing flow meters and gas composition monitors on the flare gas lines and having automated steam rate controls allows for improved flare gas combustion control, and minimizes periods of poor flare combustion efficiencies.

(3) Refrigerated Condensers for Process Unit Distillation Columns

For refineries that are rich in fuel gas, an alternative to a flare gas recovery system and CHP unit may be the use of a refrigerated condenser for distillation column overheads. Product recovery may be limited by the temperature of the distillation unit overhead condenser, causing more gas to be sent to the refinery fuel gas system and/or flare. The recovery temperature can be reduced by installing a waste heat driven refrigeration plant. A refinery in Colorado installed such a system in 1997 on a catalytic reforming unit distillation column and was able to recover 65,000 bbl/yr of LPG that was previously flared or used as a fuel. The payback of the system was about 1.5 years.

Cracking Units

Catalytic Cracking Units

(1) Power/Waste Heat Recovery

The most likely candidate for energy recovery at a refinery is the FCCU, although recovery may also be obtained from the hydrocracker and any other process that operates at elevated pressure or temperature. Most facilities currently employ a waste heat boiler and/or a power recovery turbine or turbo expander to recover energy from the FCCU catalyst regenerator exhaust. Existing energy recovery units should be evaluated for potential upgrading. One refinery replaced an older recovery turbine and saw a power savings of 22 MW and will export 4 MW to the power grid. Another facility replaced a turbo expander and realized a savings of 18 TBtu/yr.

(2) High-Efficiency Regenerators

High efficiency regenerators are specially designed to allow complete combustion of coke deposits without the need for a post-combustion device reducing auxiliary fuel combustion associated with a CO boiler.

(3) Additional Considerations

Catalytic cracking units are significant fuel gas producers. As such, an FCCU can significantly alter the fuel gas balance of the refinery and may cause the refinery to be fuel gas rich (produce more fuel gas than it consumes) or increase the frequency of flare gas system over-pressurization to the flare. GHG measures for fuel gas systems could be considered. Flare gas recovery for the impacted flare(s) could also be considered. Also, an FCCU will have a process heater to heat the feed, so GHG reduction measures for process heaters may also need to be considered. Finally, as FCCUs are one of the largest single CO_2 emission sources at a refinery, carbon capture techniques (Section 3.3.1.4) could be considered.

Hydrocracking Units

(1) Power/Waste Heat Recovery

For hydrocracker units, power can be recovered from the pressure difference between the reactor and fractionation stages. In 1993, one refinery in the Netherlands installed a 910 kW power recovery turbine to replace the throttle at its hydrocracker unit at a cost of $ 1.2 million (1993$). The turbine produced about 7.3 million kilowatt hour per year (kWh/yr) and had a payback period of 2.5 years.

(2) Hydrogen Recovery

The hydrocracking unit is a significant consumer of hydrogen. Therefore, it is likely that a hydrocracking unit will significantly impact hydrogen production rates at the refinery (if the hydrogen production unit is captive to the refinery, i.e., under common ownership or control). The off-gas stream of the hydrocracker contains a significant amount of hydrogen, which is typically compressed, recovered, and recycled to the hydrocracking unit. When the recovery compressor fails or is taken off-line for maintenance, this high hydrogen gas stream is typically flared. A back-up recovery compressor could be considered for this high hydrogen stream. Although the flaring of hydrogen does not directly produce GHG, if natural gas is added to supplement the heating value of the flare gas, then flaring of the gas stream generates GHG. More importantly, the recovery of the hydrogen in this off-gas directly impacts the net quantity of new hydrogen that has to be produced for the unit. As hydrogen production has a large CO_2 intensity, continuous recovery of this high hydrogen gas stream can result in significant CO_2 emission reductions. At one Texas refinery, replacement of the hydrogen gas stream recovery compressor took 6 months, over which period approximately 7,000 tonnes of H2 was flared, which corresponds to 63,000 to 70,000 tonnes of CO_2 emissions from additional hydrogen production. Considering the annualized capital cost of a back-up recovery compressor, the costs associated with the GHG emission reductions in this instance would be approximately $20 per tonne of CO_2 reduced.

(3) Additional Considerations

Hydrocracking units produce fuel gas. As such, GHG measures for fuel gas systems are likely applicable for hydrocracking units. Additionally, flare gas recovery for the impacted flare(s) could be considered. The hydrocracking unit will have a process heater to heat the feed, so GHG reduction measures for process heaters may also need to be considered.

Coking Units

Fluid Coking Units

(1) Power/Waste Heat Recovery

The fluid coking unit is an excellent candidate for energy recovery at a refinery. A CO boiler is used to combust the high CO off-gas from the fluid coking unit. Steam generation and/or a power recovery turbine or turbo expander could be used to recover energy from the CO boiler and its exhaust stream. Existing energy recovery units could be evaluated for potential upgrading.

(2) Additional Considerations

Fluid coking units are significant fuel gas producers; GHG measures for fuel gas systems should be considered. Flare gas recovery for the impacted flare(s) could also be considered. The fluid coking unit will have a process heater to preheat the feed. Heat recovery systems could be considered for feed preheat; GHG reduction measures for process heaters may also need to be considered. Finally, as fluid coking units are one of the largest single CO_2 emission sources at a refinery, carbon capture techniques (Section 3.3.3.1.4) could be considered.

Flexicoking Units

Flexicoking coking units primarily produce a low-heating value fuel gas. Heat recovery from the produced gas stream should be used to preheat feed or to generate steam. The low-heating value fuel gas is typically combusted in specialized boilers and the GHG reduction measures for boilers could be reviewed. Also, flare gas recovery for the impacted flares and GHG reduction measures for process heaters may also need to be considered.

Delayed Coking Units

(1) Steam Blowdown System

Delayed coking units use steam to purge and cool coke drums that have been filled with coke as the first step in the decoking process. A closed blowdown system for this steam purge controls both VOCs and methane. The steam to the blowdown system from a DCU will contain significant concentrations of methane and light VOCs. These systems could be enclosed to prevent fugitive emissions from the offgas or collected water streams. The noncondensibles from the blowdown system could be either recovered or directly sent to a combustion device, preferably a process heater or boiler rather than a flare to recover the energy value of the light hydrocarbons. Note that the sulfur content of this gas may prevent its direct combustion without treatment to remove sulfur.

As noted previously in Section 5.1.1.7 (regarding steam generating boilers), the blowdown system could be designed to operate at low pressures, so the DCU can continue to purge to the blowdown system rather than to atmosphere for extended periods. Also, a recovery unit to recycle hot blowdown system water for steam generation should be evaluated to improve the energy efficiency associated with the DCU’s steam requirements.

(2)Steam Vent

The DCU “steam vent” is potentially a significant emission source of both methane and VOCs. While not completely understood, the emissions from this vent are expected to increase based on the coke drum vessel pressure and the average temperature when the steam off-gas is first diverted to the atmosphere at (rather than to the blowdown system) at the end of the coke drum purge and cooling cycle. Generally, cycle times of 16 to 20 hours are needed to purge, cool, and drain the coke drum vessels, cut the coke out, and preheat the vessel prior to receiving feed. In efforts to increase throughput of the unit, reduced cycle times are used, but this generally requires depressurization of the coke drum at higher temperatures and pressures leading to higher emissions. While larger coke drums may have slightly higher emissions than smaller coke drums, the temperature of the coke drum when the drum is first vented to atmosphere will have a more significant impact on the volume of gas vented to the atmosphere than does the size (volume) of the coke drum. Cycle times of less than 16 hours are an indicator that the purging/quench cycles may be too short, leading to excessive and unnecessary VOC and CH_4 emissions. 40 CFR Part 60 subpart Ja requires new DCU to not vent to the atmosphere until a vessel pressure of 5 psig or less is reached. At this pressure, the equilibrium coke bed temperature should be approximately 230°F. However, as the vessel will be continuously purging to the blowdown system, the bed temperature may be significantly higher even though the pressure of the vessel is below 5 pounds per square inch gauge (psig) depending on the cycle time. A DCU could be designed to allow depressurization to very low pressures (*e.g.*, 2 psig) prior to having to go to atmosphere (which will impact the blowdown system design) to allow flexibility in operation. Analysis of the CH_4 and VOC emissions at different temperatures and pressures could be conducted to determine operational parameters for the DCU depressurization/steam vent.

(3) Additional Considerations

Delayed coking units are significant fuel gas producers. As such, GHG measures for fuel gas systems and flares could be considered. The fluid coking unit will have a process heater to preheat the feed. Heat recovery systems could be considered for feed preheat; GHG reduction measures for process heaters may also need to be considered.

Catalytic Reforming Units

The catalytic reforming unit is a net producer of hydrogen, so it can be considered as a means to produce hydrogen needed for other processes at the petroleum refineries; more detailed discussion of this is provided in Section 3.3.3.7. The reforming reaction is endothermic, so the catalytic reforming unit has large process heaters to maintain the reaction; GHG reduction measures for the process heaters could be considered. The catalytic reforming unit will also produce fuel gas so that GHG reduction measures for fuel gas systems and flares could be considered.

Sulfur Recovery Units

Nearly all refineries use the Claus-based sulfur recovery units, although some small refineries use LoCat™ system. There are, however, some variations on the traditional Claus system (*e.g.*, SuperClaus® and EuroClaus®) and a variety of different tail gas treatment units that are used in conjunction with the Claus sulfur recovery systems (*e.g.*, SCOT, Beavon/amine; Beavon/Stretford; Cansolv®, LoCat®, and Wellman-Lord). The energy and CO_2 intensities of these different systems could be evaluated (in conjunction with their sulfur recovery efficiencies) for sulfur recovery systems.

Hydrogen Production Units

Hydrotreating and hydrocracking units consume hydrogen. Hydrogen is produced as a by-product in catalytic reforming units. Hydrogen may also be produced specifically in captive or merchant hydrogen production units, which typically use steam methane reforming (SMR) techniques. Due to the importance of hydrogen for key processes and the interlinking of processes, a facility-wide hydrogen assessment could be performed to assess energy and GHG improvements that can be made. This assessment could include an assessment of whether additional catalytic reforming capacity can meet the hydrogen needs. Although both catalytic reforming and SMR are endothermic and require significant heat input, catalytic reformers produce high octane reformate (cyclic and aromatic hydrocarbons) rather than CO_2 as a result of the reforming reactions. Therefore, catalytic reforming provides a less CO_2 -intensive means of producing hydrogen as compared to SMR hydrogen production. However, there is a limited quantity of naphtha and a limited need for reformate, so catalytic reforming may not be a viable option for meeting all of the hydrogen demands of the refinery.

If a hydrogen production unit is necessary, SMR technology appears to be the most effective means of producing additional hydrogen at this time. The following technologies could be considered for SMR hydrogen production units.

Combustion Air and Feed/Steam Preheat

Heat recovery systems can be used to preheat the feed/steam and combustion air temperature. If steam export needs to be minimized, an increase in the combustion air and feed/steam temperature through the convective section of the reformer is an option that can reduce fuel usage by 42 percent and steam export by 36 percent, and result in a total energy savings of 5 percent compared to a typical SMR (ARCADIS, 2008).

Cogeneration

Cogeneration of hydrogen and electricity can be a major enhancement of energy utilization and can be applied with SMR. Hot exhaust from a gas turbine is transferred to the reformer furnace. This hot exhaust at ~540 °C still contains ~13-percent oxygen and can serve as combustion air to the reformer. Since this stream is hot, fuel consumption in the furnace is reduced. The reformer convection section is also used as a HRSG in a cogeneration design. Steam raised in the convection section can be put through either a topping or condensing turbine for additional power generation. This technology is owned by Air Products and Technip, and has been applied at six hydrogen/cogeneration facilities for refineries (ARCADIS, 2008).

Hydrogen Purification

There are three main hydrogen purification processes. These are pressure-swing adsorption, membrane separation, and cryogenic separation. The selection of the purification method depends, to some extent, on the purity of the hydrogen produced. Pressure-swing adsorption provides the highest purity of hydrogen (99.9+ percent), but all of these purification methods can produce 95 percent or higher purity hydrogen stream. When lower purity (i.e., 95%) hydrogen gas is acceptable for the refinery applications, then any of the purification methods are technically viable. In such cases, the energy and CO_2 intensity of the various purification techniques could be considered. The purification technique also impacts the ease by which CO_2 recovery and capture can be used. See also the carbon capture techniques in Section 3.3.3.1.4.

Hydrotreating Units

A number of alternative hydrotreater designs are being developed to improve efficiency. New catalysts are being developed to increase sulfur removal, and reactors are being designed to integrate process steps. While many of these designs have not yet been proven in production, others such as oxidative desulfurization and the S Zorb process have been demonstrated at refineries. The design of both modifications and new facilities could consider the current state of the art. Hydrotreaters consume hydrogen, so new hydrotreating units may also increase hydrogen production at the facility (see Section 3.3.3.7). Hydrotreaters also produce sour gas so the GHG reduction options discussed for sulfur scrubbing technologies (Section 3.3.3.2.1.3) and sulfur recovery units (Section 3.3.3.6) could be considered.

Crude Desalting and Distillation Units

Before entering the distillation tower, crude undergoes desalting at temperature ranging from 240 to 330 °F. Following desalting, crude enters a series of exchangers, known as preheat train to raise the temperature of the crude oil to approximately 500 °F. A direct-fired furnace is typically then used to heat the crude oil to between 650 and 750 °F before the crude oil is transferred to the flash zone of the tower. The crude oil furnaces are among the largest process heaters at the refinery; GHG reduction measures for these furnaces could be considered. Also, as the crude distillation unit employs among the largest process heaters at a refinery, carbon capture techniques (Section 3.3.3.1.4) could be considered. Additional GHG reduction measures are described below.

Desalter Design

Alternative designs for the desalter, such as multi-stage units and combinations of AC and DC fields, may increase efficiency and reduce energy consumption.

Progressive Distillation Design

In the conventional scheme, all the crude feed is heated to a high temperature through the furnace prior to entering the atmospheric tower. Some lighter components of crude are superheated in the furnace, resulting in an irreversible energy waste. The progressive distillation process uses a series of distillation towers working at different temperatures (see **Figure 24**). The advantage of progressive distillation is that it avoids superheating of light fractions to temperatures higher than strictly necessary for their separation. The energy savings with progressive distillation has been reported to be approximately 30 percent (ARCADIS, 2008). Crude heaters account for approximately 25 percent of process combustion CO_2 emissions (Coburn, 2007); therefore, progressive distillation can reduce nationwide GHG emissions from petroleum refineries by almost 5 percent.

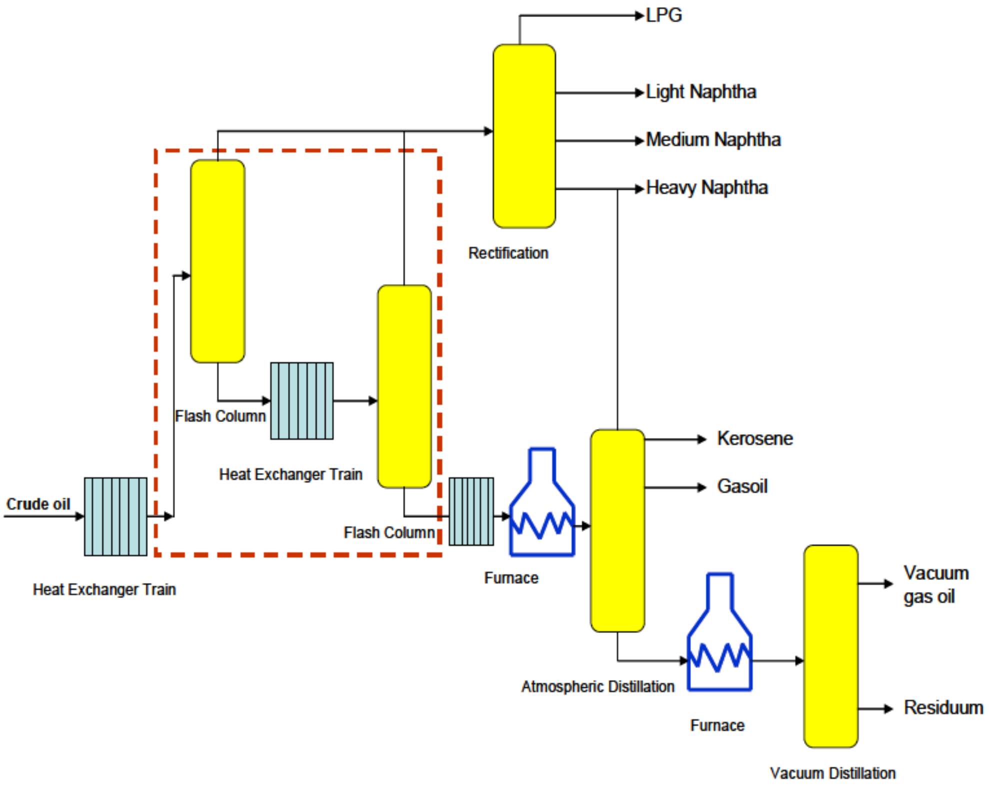


Figure 24. Process schematic of a progressive distillation process (from ARCADIS, 2008).

Storage Tanks

Vapor Recovery or Control for Unstabilized Crude Oil Tanks

Crude oil often contains methane and other light hydrocarbons that are dissolved in the crude oil because the crude oil is “stored” within the wells under pressure. When the crude oil is pumped from the wells and subsequently stored at atmospheric pressures, CH_4 and other light hydrocarbons are released from the crude oil and emitted from the atmospheric storage tanks. Most refineries receive crude oil that has been stored for several days to several weeks at atmospheric pressures prior to receipt at the refinery. These stabilized crude oils have limited GHG emissions. If a refinery receives crude oil straight from a production well via pipeline without being stored for several days at atmospheric pressures, the crude oil may contain significant quantities of methane and light VOC. When this “unstabilized” crude oil is first stored at the refinery at atmospheric conditions, the methane and gaseous VOC will evolve from the crude oil. Common tank controls, such as floating roofs, are ineffective at reducing these emissions. If a refinery receives unstabilized crude oil, a fixed roof tank vented to a gas recovery system of control device could be considered to reduce the GHG (particularly CH_4) emissions from these tanks.

Heated Storage Tank Insulation

Some storage tanks are heated to control viscosity of the stored product. A study at a refinery found that insulating an 80,000 bbl, storage tank that is heated to 225 °F could save $148,000 in energy costs.

4.4. Real reduction ability analysis of Manufacturing-fertilizer

Table 63. Real reduction ability of Manufacturing-fertilizer industry

Technology	Emission sources	Mechanism	Rate of mitigation
The 3-1 stage natural gas reforming and one-step isopiestic transformation method	ammonia synthesis	reducing carbon dioxide emissions from synthetic ammonia and improving CO_2 recycling rate	27.3%
Equipment efficiency enhancing measures	energy consumption	improving energy efficiency	12.4%
Carbon capture and storage	the whole process of production	monitoring the whole process of production	95%

4.4. 1 Carbon emission analysis

Yara Belle Plaine produces an average of 3,000 tons of urea, 700 tons of UAN and 1,900 tons of ammonia per day.

Ammonia is produced by several of Yara's 30 plants by directly combining hydrogen and nitrogen with a catalyst. The ammonia that Yara manufactures is mostly produced with natural gas as a base. Natural gas is the cleanest hydrocarbon source available. Ammonia has a use in fertilizers but also in many industrial applications. Yara is the world's leading manufacturer and trader of ammonia. They trade about one third of the world's ammonia, making Yara a world leader in supply and safe transport of ammonia in different states. Since 1905, Yara apply their knowledge to deliver this to many industrial customers safely and on time. Product stewardship in ammonia is one of focus areas.

The following Figure 25 illustrates the process of ammonia synthesis. The majority of the ammonia produced is used in the production of UAN and granular urea. Meanwhile, urea is a hot concentrated solution produced by the reaction of ammonia with carbon dioxide. When dissolved with water, this concentrated urea hot-melt liquid becomes an aqueous urea solution or a feedstock for the prilling or granulating process.

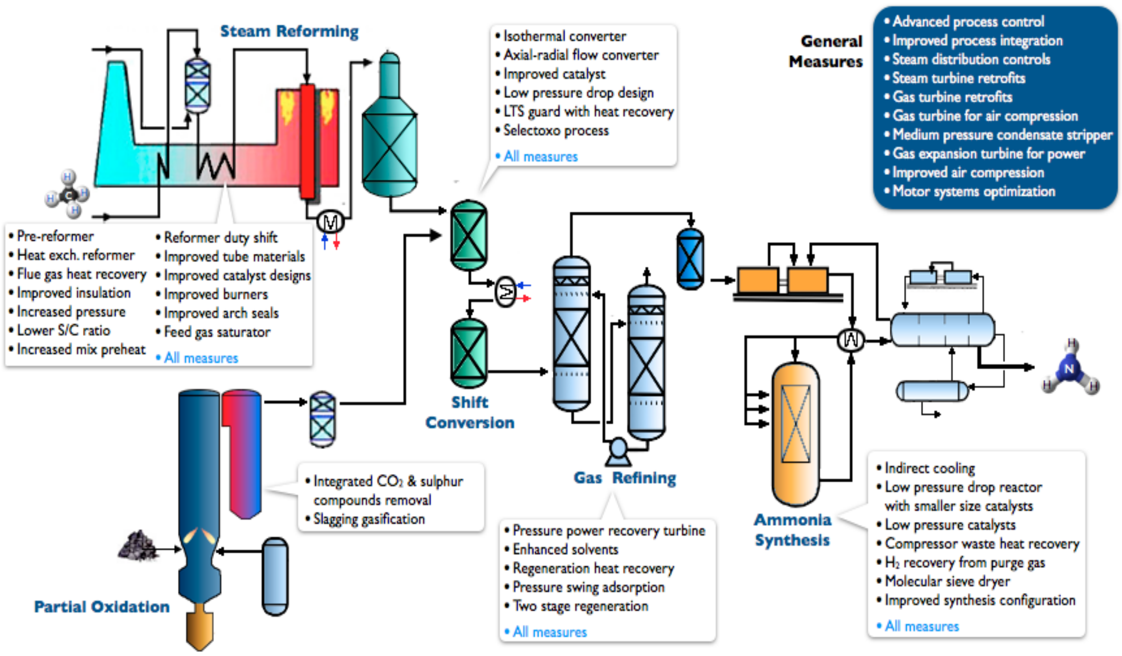


Figure 25. Process of ammonia synthesis

Productions of ammonia and UAN are energy and resource intensive. In the works of several authors, energy losses in the process have been identified and possible alternatives for reduced energy consumption have been shown.

In the process of production, according to the technical principle, the process of ammonia synthesis and energy consumption are two main sources of carbon emission. On the basis of the general reaction equation of conventional two-stage steam conversion, 1.13 tons of natural gas is consumed for every 1 ton of ammonia, at the same time, 1.16 tons of carbon dioxide is emitted. Therefore, we can calculate that yara belle plaine produces 2,270 tons of carbon dioxide emissions per day during the process of ammonia synthesis. Some of this carbon dioxide is recycled for the synthesis of urea, while another part of the carbon dioxide is discharged with exhaust fumes.

Assuming that the carbon dioxide recycling rate is 80%, yara belle plaine will emit 165,710 tonnes of carbon dioxide per year in the process of ammonia synthesis and 292,350 tons of carbon dioxide per year from energy consumption. For these two types of emission sources, we provide a variety of advanced technical solutions for reference to reduce emissions, and the following will introduce these technologies in detail.

4.4.2. Advanced technology

The 3-1 stage natural gas reforming and one-step isopiestic transformation method

In this technology, the externally heated steam reforming section takes 10%-15% CH4 load to provide high-temperature primary-reformer gas (>650℃) for equipment startup and oxidation at the auto - thermal reforming section with the remaining 85%-90% CH4 load taken by the heat exchange section and the secondary reformer pure oxygen auto-thermal reforming section. The heat exchange process in this technology uses the natural gas used as fuel in traditional 2-stage steam reforming technology for heating (the gas accounts for1/5~1/4 of all natural gas used) as feedstock, reducing the natural gas consumption in producing one ton of synthetic ammonia to 800-850m^3 from 1000m^3 of traditional 2 -stage steam reforming methods. Compared with traditional 1 -stage externally heated steam reforming technology, the 3-1 stage pure oxygen reforming syngas technology reduces fuel gas use by 85%-90% as well as CO_2 emissions. It takes 6-8 days to commission a unit using this technology and to put it into operation, a significantly shorter lead time. The article presents engineering design options for expanding natural gas-synthetic ammonia units using this new technology as well as production schemes for producing ammonia and urea as a by-product using the 3-1 stage natural gas reforming and one-step isopiestic transformation method.

The production process consists of three stages of natural gas heat transfer conversion, one isothermal transformation, conversion gas cogeneration urea, methanation, and ammonia synthesis unit processes to ultimately produce urea. The catalysts used were four kinds of nickel catalysts for conversion, copper-based catalysts for conversion, nickel catalysts for methanation, and iron catalysts for ammonia synthesis. The traditional method of producing urea is a two-step process. Synthetic ammonia is used as a single intermediate product. It has a huge liquid ammonia storage tank for the production of urea raw materials, and CO_2 needs to be removed during the production process, and then heated and recompressed for supply. Urea production is used as raw gas.

The traditional method from the natural gas feed to the production of urea generally takes 10 to 20 days, and the one-step natural gas process for urea production can be shortened to 6 to 8 days. The embodiment can be carried out by using air temperature rising (also can be used as air N2 gas rising temperature) steam switching as a carrier without the need for additional setting devices. The converted catalyst is used for baking. The ammonia synthesis is converted and transformed with a pre-reduced catalyst while being switched with air-enhanced steam. When converted into raw natural gas, the converted gas after conversion is used as conversion H2 reduction gas and conversion temperature- recovery time 3~4 d urinary decarburization and methanation takes 1d, ammonia synthesis prereduction catalyst needs 2~3 d to warm up and reduce, and the total time from driving to production is 6~8d, which greatly shortens equipment operation cycle and saves energy use.

Equipment efficiency enhancing measures - an efficiency assessment

This technology, using Pinch analysis and steam network modeling, systematically analyzes all aspects of the production process, so as to maximize the energy efficiency of each link.

Ammonia sites are great sources of greenhouse gas emissions, due to the high fuel consumption required by the energy-intensive ammonia production process. Even within the most efficient regions, natural gas costs represent more than 80% of total ammonia production costs, reaching 90% in some cases. It is thereby an indisputable fact that the profitability of ammonia production plants is increasingly endangered by fuel prices and the recent law scenarios, that impose more stringent restrictions for European Union in matters of CO_2 .

In this scenario, continuous energy efficiency improvement is needed in ammonia sites, aimed at reducing energy consumption and CO_2 emissions levels. In this respect, comprehensive efficiency studies represent a valuable aid to the progressive reduction of specific consumptions, tending to the achievement of best specific consumption values globally registered. In order to identify the real potentials of improvement and thus maximize the obtainable savings in energy costs, in-depth studies are needed, which integrate rigorous methodologies and effective techniques to detect and assess energy efficiency projects

Steam turbines - Reducing condensing pressure

Driving steam turbines of syngas and air compressors are the largest steam consumers of the plant, being therefore equipment of key interest for the energy costs reduction study. Condensing pressure in steam turbines affects directly its specific consumption, as it determines the enthalpy difference associated to steam expansion through the turbine (Figure 26). Condensation is currently carried out by means of air cooled condensers, being therefore the condensing pressure and thus the steam consumption critically affected by ambient conditions. Highest steam consumption values are reached in summer months, when the equipment operates at higher temperature levels that lead to higher condensing pressure values.

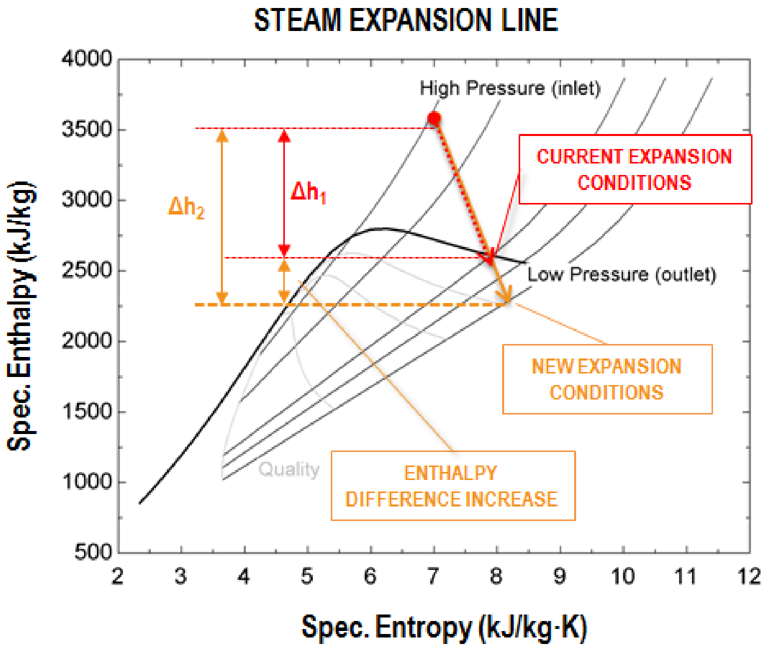


Figure 26. Reducing condensing pressure in steam turbines Schematic Mollier diagram

The reference condensing pressure for project assessment was set to 0, 2 bara, corresponding to the average value registered during one year of operation of the condensers. Therefore, it was detected the opportunity of reducing steam consumption by enhancing the condensation system and thus reducing the operating condensing pressures in both turbines. Two options were assessed for the modification of the existing cooling equipment:

- Option 1: Substitution of the air cooler by a surface condenser. By this means, increase of condensing duty is expected, due to the mayor heat rejected by using cooling water as refrigerant.
- Option 2: Installing an evaporative cooler in the existing air cooled condenser. This equipment allows reducing the air temperature in an adiabatic process that involves heat transfer from air to water droplets for liquid-to-vapor conversion (Figure 27).

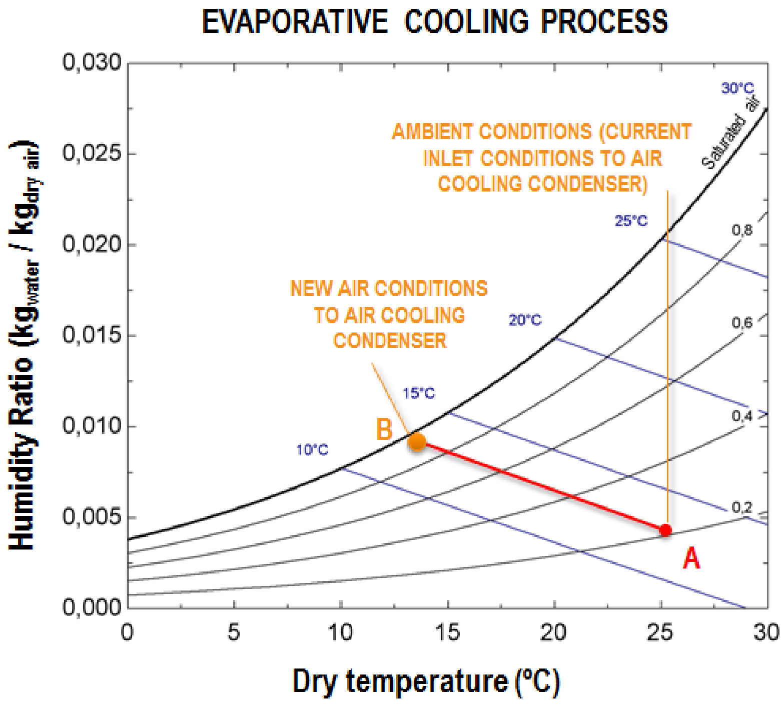


Figure 27. Psicrometric diagram of an evaporative cooling

Although Option 2 constitutes a significant improvement in terms of lower operating temperature and cooling duty increase, greater improvement in cooling capacity is expected with Option 1, as a result of using cooling water as a refrigerant. On the other hand, higher investment costs are required for this option, associated with higher costs of a surface condenser (compared to an evaporative cooler) and the installation of a new cooling tower (to cool the water supplied to the condenser) and a new circulating pump.

An in-depth analysis of the ambient conditions and the operating performance of cooling towers was needed, in order to reliably assess the economic feasibility of each option. A great sensitivity of the results was observed to ambient conditions:

- Surface condenser: Cooling water temperature varies according to ambient conditions which affect the performance of the cooling towers, as well as the operation of cooling towers by itself (fan and cooling water flowrates regulation, deterioration state, etc.).
- Evaporative cooler: The effectiveness of the equipment (and thus minimum reachable air temperature) is determined by the difference between the ambient wet-bulb temperature (which is determined by both temperature and humidity) and the actual ambient dry-bulb temperature.

Syngas compressor driving turbine - Enabling extraction

It was proposed the production of MP steam by expanding HP steam through the driving steam turbines of syngas compressors, reducing HP letdown to 0, 2 t/h (Figure 28). This allows a better use of the HP steam: in the existing configuration the steam is simply expanded through a valve and no power generation takes places through this expansion. Savings of 657.000 € were obtained, with a payback time of 1 year.

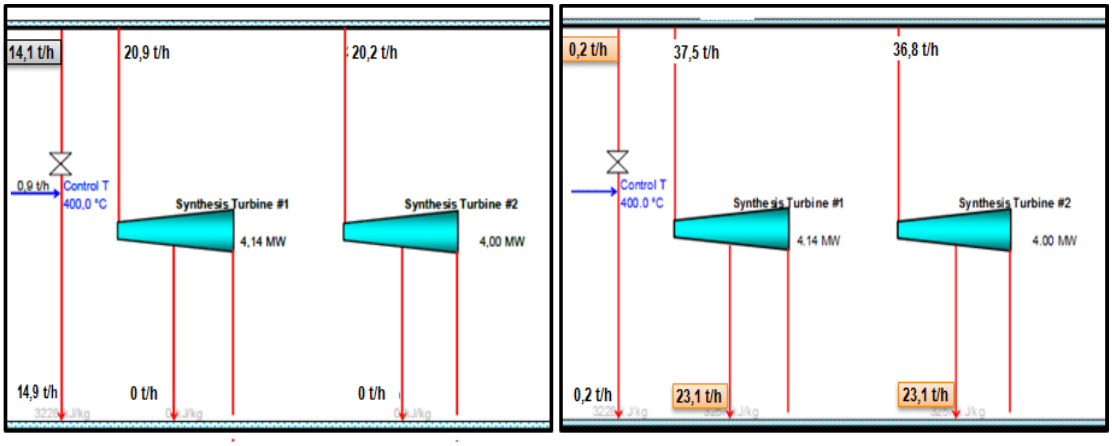


Figure 28. Enabling extraction in syngas compressor driving turbine. Operation conditions in existing (above) and new situation

Compressors – inlet and intermediate cooling

The option of reducing inlet and intermediate flow temperatures was analyzed, to enhance the operating performance of both syngas and air compressors. Shaft work required for compressing the same mass flow is thus reduced, and steam consumption decreases in the driving steam turbines. The minimum flow temperature was set to 5ºC, for those chilling technologies that allow reaching this value, which can be considered a safe value to prevent undesirable effects such as:

- Ice formation and consequent mechanical damage to the compressor blades.
- Compressor surge, that can manifest as a consequence of excessive increase of the density of the compressed gas and the consequent reduction of the volumetric flow rate.
- Different options were assessed regarding cooling options:
- Mechanical chillers.
- Absorption chillers: Libr/H2O or NH3/H2O equipment were contemplated. For both cases, hot water was considered for heat supply to the generator, obtained by heat recovery from the process.

Figure 29 represents the configuration proposed for the air compressor. The cooling power supplied by the chiller through the glycoled water circuit is transferred to the cooled stream by means of a new heat exchanger. No cooling is proposed for the inlet stream to the last compression stage. This responds to security reasons, aiming at avoiding any alteration in the operation conditions (pressure and temperature) of the air stream fed to the process.

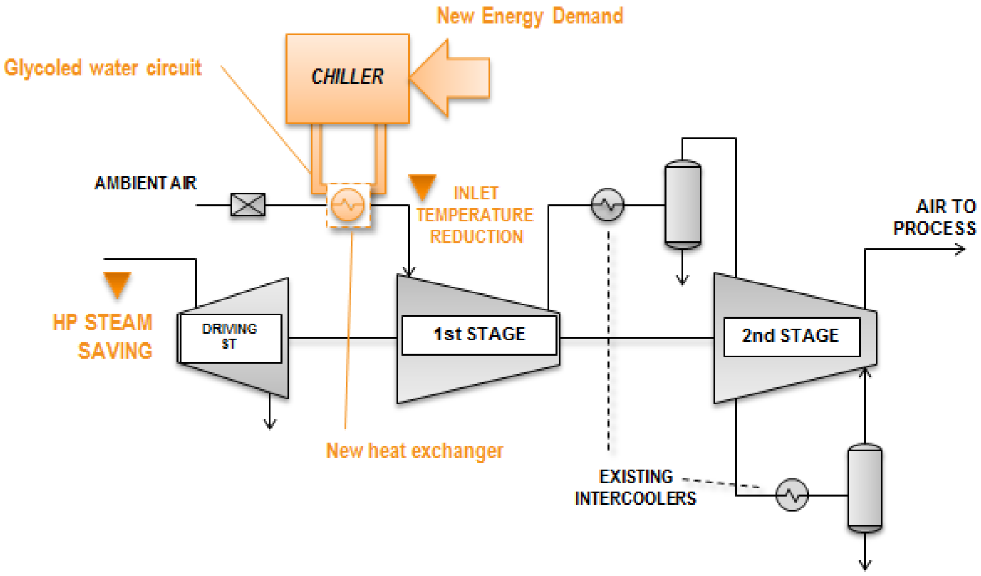


Figure 29. Inlet and intermediate cooling in air compressor

The most feasible solutions detected for chilling were Libr/H2O absorption system for syngas compressor and mechanical chiller for air compressor. For the syngas compressor project, the new energy demand (which consists of heat to generator of the new absorption chiller) would be supplied by energy recovered from the process.

Despite the attractive values of PBT, the obtained savings may not compensate the complexity of the proposed changes. At the same time, the correct operation of air and syngas compressors is critical for the process, which could be determinant to decide about the implementation of the project. Nevertheless, the results are still of interest for similar future projects, and may constitute a valid aid to the optimization in the design phase of compressing systems.

Natural gas saturator

The utilization of hot condensates upstream the reformer was proposed as an option for natural gas saturation. That way the load of MP steam boiler could be reduced, as a result of steam demand reduction of steam reforming process. Calculated economic benefit associated with this measure is 507.000 €/year and resulting payback time is less than one year.

Cooling water – Upgrading water pumping system for efficiency enhancement

The replacement of the centrifugal pumps used for cooling water circulation by more efficient ones has been proposed, as a measure of improvement for the pumps of major consumption of the plant. Existing pumps have an efficiency of 78%, and expected efficiencies of the new ones are expected to range values up to 82%. It results in potential savings of 14.000 €/year, with a payback time of 2 years.

Desulphurization furnace - Optimizing combustion

One of the most critical factors in the efficiency of furnaces and other generating equipment (boilers, etc.) is the excess of air used for the combustion. For each fuel, determined values of air excess are established to ensure a complete combustion. Any increase in the air mass flow above the optimum excess value leads to important efficiency losses, as heat is wasted through exhaust gases.

For this technology, a saving opportunity was detected in reducing the existing levels in exhaust gases from its existing values down to 3%, which ensures the optimal combustion of natural gas. The current operating value in the desulphurization furnace surpassed the optimum, being measured in 14%. For this project, the implementation of an automatic combustion system which maintains in its optimal value was proposed. For the desulfurization furnace, potential savings of 60.000 €/year with a payback time lower than 1 year were obtained.

MP steam boiler - Boiler feedwater pumping system optimization

Currently, boiler feedwater (BFW) is supplied to HP (85 barg) and MP (42 barg) boilers by a unique pumping system. The great difference between these pressure levels suggested the option of separating BFW circuits, being thus MP BFW supplied by a new independent pump with significantly lower shaft power required. By this means, estimated savings of 22.700 € were obtained, with payback of less than 1 year.

Compressor driving - Replacement of steam turbine by an electric motor

Shaft power supply to any pumping or compression system can be carried out by means of electric motors or driving steam turbines. Apart from specific aspects of the operation which could force to one single option, the election of which solution is more profitable is determined by energy prices. In this case, the use of an electric motor was proposed for driving the air compressor located in the nitric plant, due to upcoming regulation laws that would lead to significative electricity prices reduction. Achievable economic saving was estimated of 1.591.000 €/year, with a payback time of less than 1 year.

The study demonstrates the significant benefits attainable with the application of this technique during the design stage of the heat exchanger network. The high enhancement potentials of Pinch analysis are specially reflected in this design stage, due to the absence of the constraints that are always present when studying existing plants, and that often make impossible the implementation of energy conservation projects. The reasons that affect the viability of such projects are both technical and economic, and in most cases these restrictions are not critical in the phase of plant design or revamp. As demonstrated by this study, Pinch analysis is a powerful tool that should always be considered for the design or the revamp of new ammonia sites, since it ensures that optimal recovery from the process and thus minimum fuel consumption is achieved. Energy savings were detected of 19.5% of fuel currently consumed in the site, through the re-design of the existing thermal network at the service of the plant.

Future developments

Actions carried out in the industry aiming at improving energy efficiency are more effective if an energy management system (EMS) is subsequently implemented, which keeps track of the energy efficiency of the facility, ensuring the maintenance over time of the efficiency levels reached once the improvements have been implemented. As a result of this necessity, the standard ISO 5000 is increasingly being implemented in big companies. This standard defines the main objectives that any EMS should fulfill (personnel involved, documentation needed, etc.). Nevertheless, the contents of ISO 50001 are not exhaustive regarding the definition of specific guidelines for the proper development and implementation of the EMS. Moreover, EMS services should be improved regarding the following aspects:

- Expert personnel in energy efficiency, which, in conjunction with technical experts in management systems and ISO standards, fulfill the successful implementation of EMS, achieving and maintaining real reduction of energy costs. Over its experience in implementing EMS according to ISO 50001, DVA has proved the necessity of considering this aspect in any project of this nature. This expertise provides a specific energy efficiency approach over the course of the project and ensures that adequate results are obtained.
- Energy management, analysis and optimization tools, which provide plant staff with effective real-time monitoring software to carry out the energy management of the process.

Carbon capture and storage

Energy sources such as oil, natural gas, and coal currently account for around 80% of the world’s primary energy consumption. Despite significant investments in renewable energy and energy efficiency, that Canada and others are making, the International Energy Agency (IEA) has forecast that as the global economy continues to grow, fossil fuels will continue to dominate the world’s energy supply for decades. Reconciling the world’s ongoing reliance on fossil fuels with the need to reduce greenhouse gas (GHG) emissions is then one of our greatest challenges. Canada is taking this challenge seriously with climate change policies that include enhancing our global leadership in advancing one of the most promising technologies for reducing GHG emissions from fossil fuel use: carbon capture and storage (CCS).

CCS is only one of several technologies that must be deployed and is not a ‘silver-bullet’ for meeting Canada’s target of reducing its GHG emissions by 17% from 2005 levels by 2020. Yet, CCS is one of the only technologies currently available for making emissions reductions from large-scale fossil fuel usage - and, thus, will be a critical component of the technology puzzle for Canada to meet its emissions reduction objectives.

Canada has a number of key sectors where the deployment of CCS is needed and there are opportunities to advance the technology. These include coal-fired electricity plants, the oil sands, and natural gas processing (e.g. from the new development of shale gas) - though the opportunity and demand for advancing CCS technology also exists in other sectors such as chemicals, fertilizer, steel making, and cement.

Federal and provincial governments in Canada are making substantial investments in CCS, committing upwards of $3 billion in public funding towards seven large-scale fully-integrated CCS demonstration projects. The federal ecoENERGY Technology Initiative announced $151 million for the initial engineering and/or pilot stages of seven potential demonstration projects in 2008. The 2009 federal budget created Clean Energy Fund, which included $610 million for CCS demonstrations. The Provinces of Alberta, Saskatchewan, and British Columbia have also committed funding for demonstrations, in particular $2 billion by Alberta. This public funding will leverage additional investment from industry, for projects that will each capture and store on the order of 1 million tonnes of CO_2 per year.

Importance of carbon capture and storage (CCS) in Canada

Energy sources such as oil, natural gas, and coal currently account for around 80% of the world's primary energy consumption. Despite significant investments in renewable energy and energy efficiency that Canada and others are making, the International Energy Agency (IEA) has forecast that as the global economy continues to grow, fossil fuels will continue to dominate the world's energy supply for decades.

There is a similar story in Canada where fossil fuels currently supply the vast majority (88%) of the country's energy needs and will continue to do so for several decades as it transitions to a low carbon economy. Canada's economic prosperity is also linked to being a major energy producer. In 2008, 38% of energy produced in Canada was exported, primarily to the United States, which points to the increasing importance of Canada's energy sector for continental energy security.

Canada has inscribed in the Copenhagen Accord a 2020 economy-wide target of a 17 percent reduction in greenhouse gas (GHG) emissions from 2005. Reconciling Canada's ongoing reliance on fossil fuels with the need to reduce GHG emissions is one of the country's greatest challenges. Canada is taking this challenge seriously with policies that include enhancing its global leadership in advancing carbon capture and storage (CCS). As the leading technology available for making emissions reductions from large-scale fossil fuel use and production, CCS will be a critical component of the suite of GHG mitigation measures being undertaken in Canada.

Opportunities and challenges

Canada is a global leader in CCS, with governments, industry and non-governmental organizations all moving forward with CCS initiatives. The provinces of Alberta, Saskatchewan, and British Columbia, in particular, are at the forefront of CCS development in terms of research, demonstration projects, and regulatory frameworks. Other provinces such as Nova Scotia, Quebec, Ontario and Manitoba are also moving forward with CCS activities.

Canada has experience with the various components of CCS from decades of analogous activities in the oil and gas sector that involve the capture, transport, injection or storage of liquid and gaseous substances. Saskatchewan is home to the Weyburn-Midale Project, one of the world's five fully integrated commercial-scale CCS projects.

Canada also has a natural advantage when it comes to CO_2 storage. The Western Canadian Sedimentary Basin has excellent geological storage potential in close proximity to a concentration of large final emitters. Preliminary estimates of storage capacity include 450 megatonnes (Mt) for enhanced oil recovery (EOR) opportunities in Western Canada and at least 3 gigatonnes of total CO_2 storage in the province of Alberta alone . Storage potential also exists in other parts of the country, such as Atlantic Canada.

There are a number of key sectors in Canada where the deployment of CCS is needed and where there are opportunities to advance the technology. These include coal-fired electricity, natural gas processing, and the oil sands. The oil sands are Canada s unique challenge for advancing CCS. Unlike power plants, oil sands facilities have multiple point sources of emissions that vary in size and concentration of CO_2. Advancing CCS in this sector will be strategically important for addressing the overall environmental footprint of the oil sands sector. The opportunity and demand for advancing CCS also exists in other sectors such as chemicals, fertilizer, and steel and cement production.

Notwithstanding the work Canada is already doing, there remain several challenges facing the commercial deployment of CCS. The foremost challenge is the high cost of CCS projects. A financial gap currently exists for most commercial-scale CCS projects since the incremental costs for implementing CCS are higher than the potential economic benefits generated from the project. Measures to narrow this gap include market-based or regulatory mechanisms, financial incentives, direct funding for demonstration projects, and investment into research and development to reduce costs.

The scale at which CCS will have to be deployed to achieve major emissions reductions is another challenge. In Canada, around 4 million tonnes annually of CO_2 and other acid gases are captured and injected into the subsurface. While that puts us among the global leaders in demonstrating this component of CCS, rapid deployment of CO_2 capture, pipeline and storage infrastructure will be needed.

Given the unprecedented volumes of CO_2 being contemplated for transport, injection and storage, there is a need to increase scientific understanding of the environmental impacts and risks of large-scale CCS activities. There are still questions that need to be answered surrounding the environmental integrity of the injection and permanent sequestration of large volumes of CO_2. These include concerns over both the local and global environmental risks during the operational phase of a project as well as in the long term.

To move forward with CCS projects, Canada, like other countries must resolve outstanding legal and regulatory issues. Clear regulatory frameworks will provide the certainty companies need to make investment decisions about CCS. Regulatory preparedness is also essential to building public acceptance of this technology as a long term GHG mitigation option for Canada.

Public engagement is a crucial factor for advancing CCS. Given the scale of required investments, the complexity of the required infrastructure and the proximity of CO_2 storage sites to some communities, it is important to address public concerns regarding the risks and benefits of CCS projects.

Refining legal and regulatory frameworks.

Canada has decades of experience with the various components of CCS from its activities in the oil and gas sector. A number of public-private-academic advisory groups and third party experts have reported that the regulatory frameworks in place for the oil and gas sector in Canada form a solid foundation for future regulation of CCS projects. These groups and experts have also identified outstanding legal and regulatory issues and made recommendations on how to address gaps in federal and provincial legal and regulatory frameworks. Through the Canadian CCS Network, federal and provincial governments are working together to facilitate the swift resolution of these outstanding issues.

Regulatory mechanisms can serve as a key policy tool for encouraging the adoption of CCS. In June 2010, the Government of Canada announced its intent to develop greenhouse gas regulations for coal-fired power plants. Starting in 2015, all new coal-fired power plants and units reaching the end of their economic life will have to meet a stringent performance standard, based on parity with the emissions performance of high-efficiency natural gas generation. This standard could encourage investment in cleaner power generation technologies such as CCS.

4.5. Real reduction ability analysis of Manufacturing-steel

Table 64. Real reduction ability of Manufacturing-steel industry

Technical category	Technology	Substance	Rate of Mitigation
Emerging Technologies for Ironmaking Using Blast Furnace	Plasma Blast Furnace	CO_2	50%
Emerging Rolling and Finishing Technologies	Nitrogen Oxide Emission Reduction by Oscillating Combustion	NOx	75%
Carbon Capture and Storage Technologies for the Iron and Steel industry	Top-Gas Recycling in Blast Furnaces, with Carbon Capture and Storage	CO_2	75%
Carbon Capture and Storage Technologies for the Iron and Steel industry	HIsarna with Carbon Capture and Storage	CO_2	Reduction of 20 %, or 80 % if combined with CCS
Carbon Capture and Storage Technologies for the Iron and Steel industry	Post-combustion Carbon Capture Using Chemical Absorption Technologies	CO_2	Reduced by less than 50 % without shift reaction technology, and by 85 to 99.5 % with shift reaction

Iron and steel manufacturing is among the most energy-intensive industries and accounts for the largest share, approximately 27 percent, of global carbon dioxide (CO_2) emissions from the manufacturing sector. The ongoing increase in world steel demand means that this industry's energy use and CO_2 emissions continue to grow, so there is significant incentive to develop, commercialize and adopt emerging energy-efficiency and CO_2 emissions-reduction technologies for steel production. Although studies from around the world have identified a wide range of energy-efficiency technologies applicable to the steel industry that have already been commercialized, information is limited and/or scattered regarding emerging or advanced energy efficiency and low-carbon technologies that are not yet commercialized. Thus, we consolidate available information on 21 emerging iron and steel industry technologies to provide a well-structured database of information on these technologies for the improvement of emission reduction technologies for the steel industry in Saskatchewan, Canada.

Table 64 lists five different technologies that can be used for different aspects of emission reduction. Specific technical implementation and other related technologies for energy, environment and other benefits are described later. In summary, the emerging technologies have high emission reduction capabilities. In addition to reducing emissions, emerging technologies have other advantages, such as reducing acid gas emissions, reducing energy consumption, minimizing metal loss, and so on. We will later introduce steelmaking process and CO_2 emissions from typical steel mill. As for the Manufacturing-steel industry in Saskatchewan, Canada, the techniques described later can be used as a reference for reducing emissions.

Iron and steel manufacturing is one of the most energy-intensive industries worldwide. In addition, use of coal as the primary fuel for iron and steel production means that iron and steel production has among the highest carbon dioxide (CO_2) emissions of any industry. According to the International Energy Agency (IEA), the iron and steel industry accounts for the largest share – approximately 27 percent – of CO_2 emissions from the global manufacturing sector (IEA 2007).

Iron ore is chemically reduced to produce steel by one of these three process routes: blast furnace (BF)/basic oxygen furnace (BOF), smelting reduction, or direct reduction. Steel is also produced by direct melting of scrap in an electric arc furnace (EAF). Each of these processes are briefly explained below.

BF/BOF and EAF production are the most common today. In 2010, BF/BOF production accounted for approximately 65 percent of the steel manufactured worldwide, and EAF production accounted for approximately 30 percent. Iron and steel can be produced at separate facilities or in an integrated steel mill, where the iron ore is reduced into pig iron or DRI and then processed into steel at the same site.

Figure 30 is a simplified flow diagram of steel production using BF/BOF, EAF, and direct reduction. The following subsections describe the main production steps.

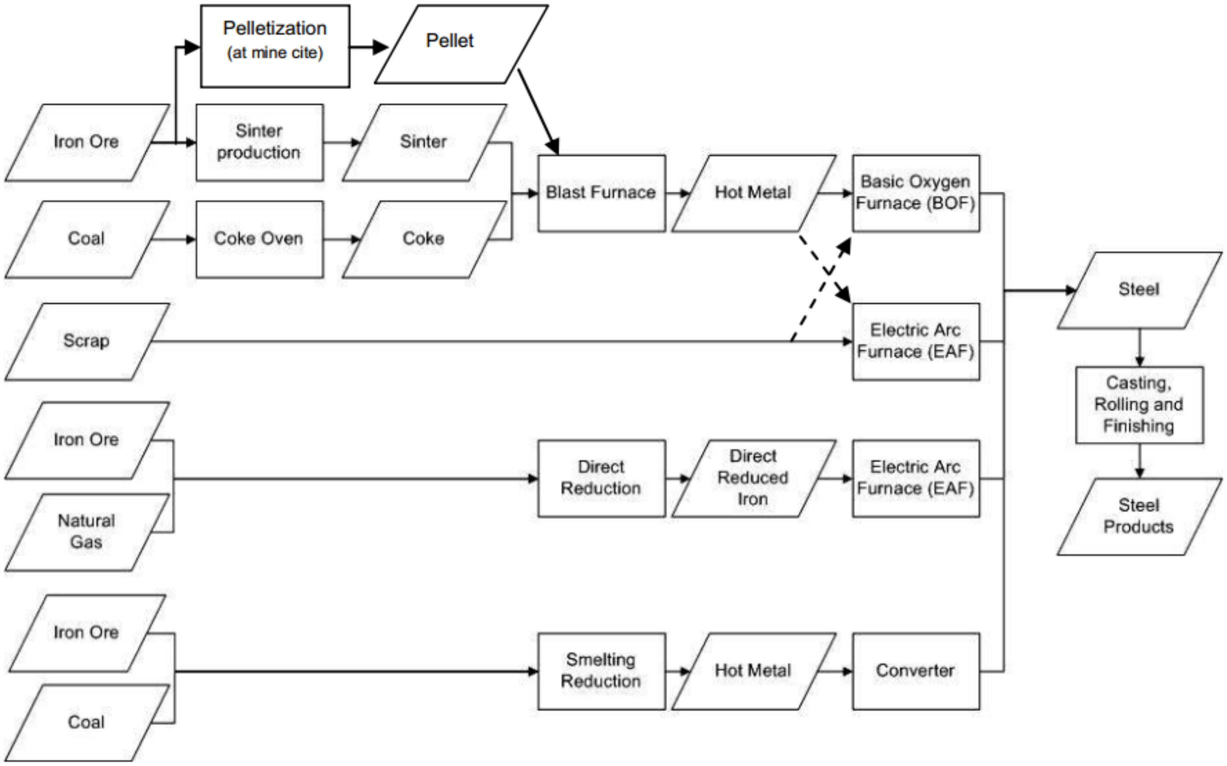


Figure 30. Flow diagram of steel production

Iron and steel production generates CO_2 emissions as 1) process emissions, in which raw materials and combustion both may contribute to CO_2 emissions; 2) emissions from combustion sources alone; and 3) indirect emissions from consumption of electricity (primarily in EAFs and in finishing operations such as rolling mills at both integrated steel plants and EAF plants).

The major process units at iron and steel facilities where raw materials, usually in combination with fuel combustion, contribute to CO_2 emissions include the sinter plant, non-recovery coke oven battery combustion stack, coke pushing, BF exhaust, BOF exhaust, and EAF exhaust. The primary combustion sources of CO_2 include: by product recovery coke oven battery combustion stack, BF stove, boiler, process heater, reheat furnace, flame-suppression system, annealing furnace, flare; ladle re-heater, and other miscellaneous.

Figure 31 shows the profile of CO_2 emissions from and material flow in a typical BF/BOF integrated steel plant. It shows that total CO_2 emissions of a typical integrated steel plant are equal to 1.8 tCO_2/t rolled coil, of which 1.7 tCO_2/t rolled coil is associated with coal use, and the other 0.1 tCO_2/t rolled coil is related to lime use.

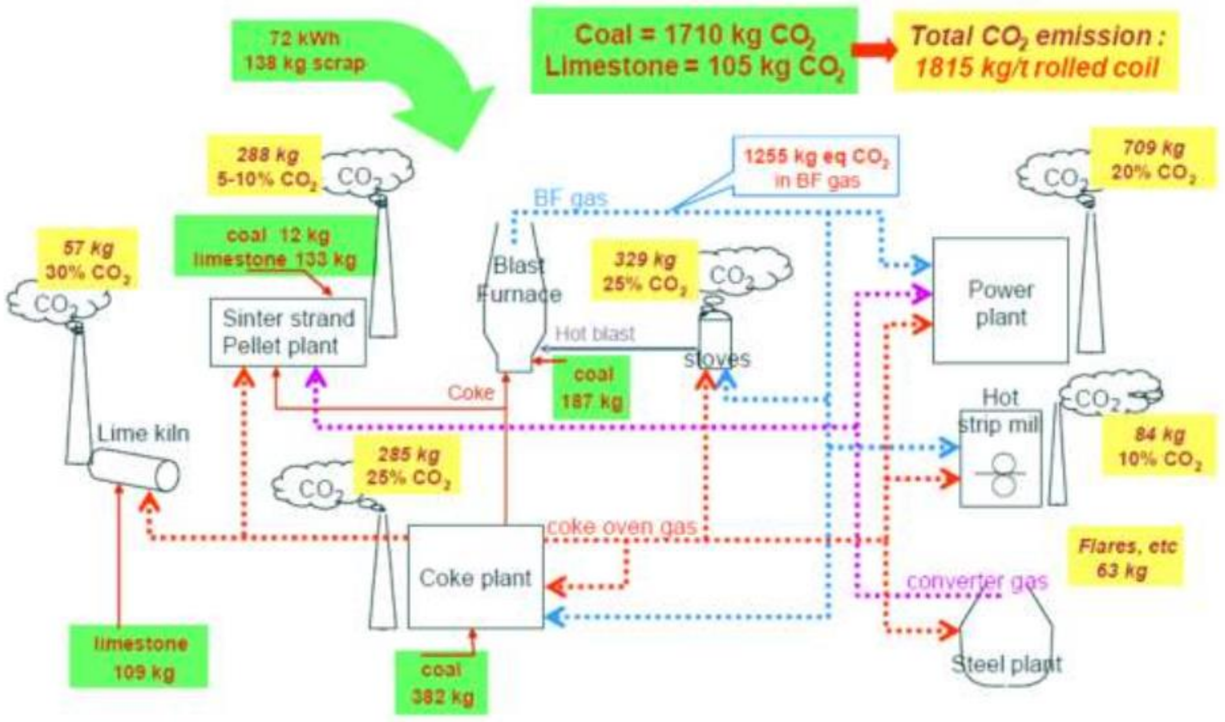


Figure 31. CO$_2$ emissions from typical steel mill

Emerging Agglomeration Technology

Iron ore agglomeration can improve the iron content and/or physical properties of the ore. Iron feed materials from such processes usually contain between 50 percent to 70 percent iron by weight. The main agglomeration processes are sintering and pelletizing. Below an emerging technology that can be applied to this stage of iron production is presented.

Use of Biomass in the Sintering Process

The iron-ore sintering process contributes up to 10 percent of the CO$_2$ emissions from an integrated iron and steel plant. This process requires the ignition of a solid fuel (usually coke breeze), which is blended into the raw feed material. A suitable alternative fuel must be solid and have downdraft combustion characteristics similar to those of coke breeze. Charcoal is an attractive alternative to coke breeze because charcoal is derived from biomass and therefore considered to be carbon neutral. Charcoal has been found to be as effective a fuel and reductant as high quality coals for the bath smelting of iron ores.

A variety of wood char products are produced using relatively new processes such as gasification, slow pyrolysis, and fast pyrolysis. Wood char has been shown to be a suitable replacement for coke breeze, improving the sintering process and reducing acid gas levels in process emissions It should be noted that it is possible that only a limited amount of charcoal would be available when competition with other routes of biomass use is considered.

Ooi et al., conducted a laboratory study of the use of hardwood charcoal as a supplementary fuel in the iron-ore sintering process. The primary fuel was coke breeze; the study tested 0 percent, 20 percent, 50 percent, and 100 percent replacement with charcoal, producing raw blends with the same heat output as coke breeze. The experimental results indicate that fuel blends with 20 percent heat input provided by charcoal may improve both sinter yield and sintering productivity by up to 8 percent under normal conditions. When larger percentages of coke breeze were replaced with charcoal, reduced sintering performance was observed, which was mainly attributed to the lower fixed carbon content and higher volatile matter content of the fuel mix.

Zandi tudied commercially available biomass materials suited to sintering: olive residues, sunflower husk pellets, almond shells, hazelnut shells, and bagasse pellets. A laboratory sinter pot was used to study the sintering behavior of these biomass materials. The calorific values of selected biomass materials, on a dry basis, were, on average, approximately 65 percent that of dry coke breeze. However, less of this energy was available in sinter making because some of the volatile matter evaporated ahead of the flame front. Replacing 25 of coke breeze with crushed sunflower husk pellets produced a thermal profile closest to that of coke breeze alone in some size ranges of sunflower husk pellets. Figure 32 shows a schematic drawing of an iron-ore sintering plant.

The following benefits can be achieved by replacing a portion of the coke breeze fuel with biomass fuel in sintering plants:

- Substantial reductions in CO_2 emissions because biomass is considered carbon neutral
- Reduced acid gas emissions
- Improved carburization rates and increased product quality
- Reduced demand for fluxing agents
- Lower slag volume and levels of process wastes
- Higher productivity through use of more reactive carbon

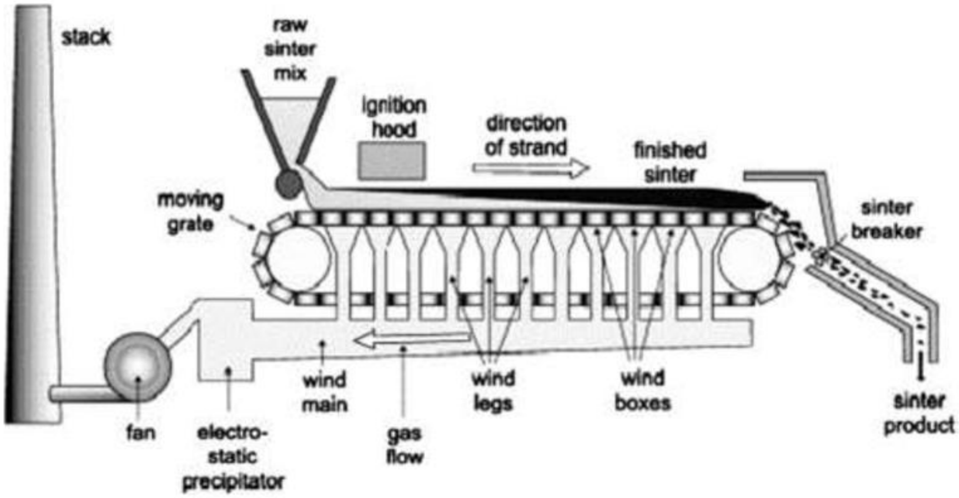


Figure 32. Schematic diagram of an iron-ore sintering plant

Emerging Coke-Making Technologies

The subsections below describe the following emerging technologies to reduce the energy use and CO_2 emissions of the coke-making process: single-chamber coke reactors and battery under-firing with advanced controls.

(1) Single-chamber-system Coking Reactors

Single-chamber-system (SCS) coking reactors are large-volume coke ovens that are 45 to 85 centimeters wide. Single-chamber reactors are separate, process-controlled units with rigid walls that can absorb high coking pressure. The single-chamber design allows much thinner heating walls than in other systems. This enhances heat transfer and combustion and allows for greater design flexibility in the plant.

The load-bearing capacity of the single-chamber reactor walls means that a greater range of coal blends can be charged than in conventional coke ovens. (Rohde and Strunk compared the coking behavior of coal blends in the single chamber system and in conventional high-capacity coke ovens.) The large-dimension oven in the SCS design reduces environmental emissions compared to those from multi-chamber reactors. SCS coke ovens are expected to take the place of current multi-chamber coke ovens whose walls have more limited flexibility. SCSs are 38- to 70-percent more thermally efficient than other coke ovens. The SCS technology is currently under development. An SCS coke reactor operating in Germany was relocated to China a few years ago.

(2) Coke Oven Under-firing with Advanced Diagnostics and Control

Heating coke ovens produces significant amount of the pollutants nitrogen oxide (NOx) and sulfur dioxide (SO_2). Therefore, improving energy efficiency of coke ovens is a cost-effective way to reduce pollutant emissions as well as energy demand. A BFI project developed individual control of the heating walls of coke ovens as well as innovative diagnostic systems that can detect disturbances in the heating walls. A test reactor (see Figure 33) was used to study factors that influence the composition of the off gas and the temperature distribution in the heating flues; these factors include combustion gas supply line position, combustion air/gas preheating temperature, combustion air/gas ratio, raw gas escape, and off-gas recirculation. Based on the results, the authors draw conclusions about the quality of the coke wall heating and devise measures to improve the efficiency of oven heating. No industrial application has been reported so far.

BFI claims that the following benefits can be achieved by coke oven under-firing with advanced diagnostics compared to conventional coke oven operation:

- Reduced energy consumption because of optimized wall heating
- Reduced NOx and SO_2 emissions as a result of reduced energy use

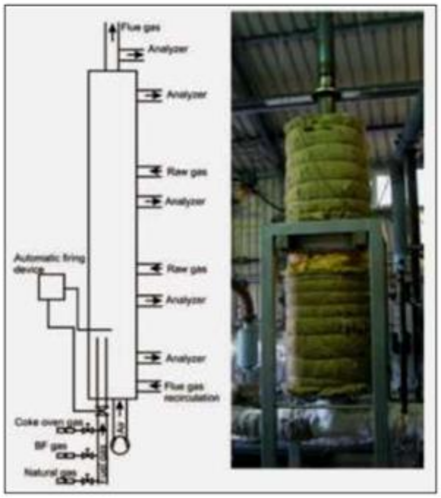


Figure 33. Coke oven heating laboratory plant schematic (left) and photograph (right).

(3) Emerging Technologies for Ironmaking Using Blast Furnace

The subsections below describe the following emerging technologies to reduce energy use and CO_2 emissions from the BF ironmaking process.

(4) Hot Oxygen Injection

Injection of pulverized coal directly into the BF bypasses the coke making process and injects coal directly into the BF at the tuyere level. Pulverized coal injection (PCI) is not a new technology, but, until now, the amount of coal that could be injected into the furnace was limited to 116 to 150 kilograms (kg)/t hot metal because of incomplete combustion of char in the tuyere zone and consequent disturbances in gas and burden flow in the furnace. Increased coal injection is needed to further lower coke requirements and allow for more flexible furnace productivity. The direct injection of high-temperature oxygen with coal in the BF blowpipe and tuyere offers better coal dispersion at high local oxygen concentrations, which optimizes oxygen use in the BF.

Praxair has developed an application in which its patented thermal nozzle technology uses oxygen to improve the combustion efficiency of injected pulverized solid fuels. This is accomplished by virtue of quicker ignition, de-volatilization of the pulverized solid fuel, and intense mixing of the solid fuel using a high-momentum, high-temperature stream of oxygen generated in situ.

In a commercial-scale project, hot oxygen injection from Praxair’s thermal nozzle system was demonstrated on two tuyeres of the U.S. Steel Gary Works BF. Heat loads were measured on all furnace components affected by hot oxygen. The results showed significantly higher levels of combustion in the blowpipe and tuyere with hot oxygen, along with acceptable increases in equipment temperature. The data suggest that hot oxygen increases injection of pulverized coal directly into the BF by 30 percent which reduces the amount of coke use in BF, thereby reducing the energy use in coke making. For a medium-sized BF producing 4,000 t per day (tpd) with a hot oxygen replacement ratio of 0.9, coke savings would be 135 tpd, and injection of pulverized coal would increase by 150 tpd. The expected increase in oxygen consumption would be 34 kg/t hot metal, or 150 tpd. In addition, increased coal injection will increase the net heat generated from BF gas by an estimated 780 GJ/day.

Based on pilot tests, the following benefits are reported for direct injection of high-temperature oxygen into the BF:

- Reduced emissions of pollutants and greenhouse gases (CO_2, SO2, volatile organic
- Compounds [VOCs], and NOx) proportional to reduced coke requirements.

(5) Blast Furnace Optimization Using Computational Fluid Dynamics Modeling

One method of visualizing BF operations is by building a “virtual BF” using computational fluid dynamics (CFD) modeling. CFD uses advanced mathematical and computing concepts to simulate the behavior of high-pressure, high-temperature systems. Using the “virtual BF,” it is possible to design, optimize, and troubleshoot the system and experiment with operational improvements. CFD can be used to model increased levels of PCI. Increasing the PCI from 116–150 kg/t hot metal to 250 kg/t hot metal would save approximately 0.33 GJ of energy/t hot metal. Efforts to increase PCI to more than 250 kg/t hot metal have been frustrated because, at these levels, the permeability of the BF bed decreases, shutting off gas flow. In addition, some of the pulverized coal is wasted because it fails to combust and is blown through the BF into the gas collection system, thus increasing the apparent energy intensity of the process.

The ability to increase the amount of coal injected into BFs has been limited by lack of knowledge of some key issues, so the U.S. DOE and American Iron and Steel Institute (AISI) Technology Roadmap Program (DOE/AISI TR Program) supported research at Purdue University-Calumet to develop high-fidelity CFD numerical simulations. To date, Purdue has developed comprehensive three-dimensional (3-D) CFD models and methodologies to simulate the entire PCI process. The models were created by comparing CFD results with experimental data and were then applied to simulate the PCI process in various BFs of AISI members, using actual furnace geometries and operating practices. The effects of key parameters, such as blast temperature and flow rate, oxygen concentration, coal type, PCI rate, and tuyere diameter, have been investigated.

The following benefits are reported for the use of CFD models for BF optimization: Reduced emissions from coke making, proportional to reduced coke requirements.

(6) Blast Furnace Optimization Using X-ray Diffraction Analytical Technique

As mentioned above, in BF ironmaking, coke consumption can be decreased by increasing the pulverized coal injection rate (PCIR). This will change in-furnace reduction conditions, burden distribution, demands on raw material strength, and other factors. To maintain stable operation and minimize material losses through off gassing, it is important to understand fines generation and behavior in the BFPCIRs greater than 100 kg/t hot metal can result in the production and accumulation of unburned coal char in the tuyere raceways. This char is entrained in the blast and carried into the burden, reducing bed permeability, and is ultimately carried into the gas cleaning system and collected in the BF sludge. Tiny particles of coke called “fines” are also produced in the furnace and behave in a similar fashion. To solve the problems related to unburned char, DOE/AISI TR Program supported research at the University of New South Wales to analyze the production of char and fines in BFs and relate this to furnace operating parameters and coal and coke properties. A novel technique using X-ray diffraction (XRD) was developed to quantify the proportion of carbon from PCIR and coke in the BF dust. XRD is used to study the microstructures of molecular and crystalline materials. The study demonstrated that blast temperature and oxygen influenced PCI combustion and char carryover and limited coal injection rates. The results suggest that, by monitoring the carbon structure of residual char in the dust, PCI and coke quality can be optimized for various process parameters. The study further demonstrated that the carbon structure of coke fines in BF dust can be used to assess coke performance, particularly the influence of temperature on the generation of coke fines, whether they originated in the low- or high-temperature zones of the BF. Introduction of this XRD diagnostic tool in steel plants makes it possible to monitor the impact of PCI rates and coke quality and thereby further boost PCI rates.

The benefits of XRD include:

- Enables use of carbon structure of BF fuels and dust emissions to select coke and optimize PCI operations
- Reduces emissions (e.g., CO_2, SO_2, VOCs, and NOx) from coke making, proportional to reduced coke requirements

(7) Plasma Blast Furnace

Today, plasma technology is being used successfully worldwide in a variety of industries from chemical and metallurgical to waste/environmental (asbestos vitrification, fly-ash destruction) and steel production (heat support for cupola and BF).

Plasmas are gaseous collections of electrically charged particles such as electrons and protons. These ionized particles carry energy; in a plasma BF, the plasma flow hits the metal surface, the ions release their energy, which melts the metal. Typical plasma power ranges from 1 to 4 megawatts electric. Plasma torches provide high-temperature gas streams (up to 5,000°C). Thermal-plasma systems fall into two categories: nontransferred-arc and transferred-arc devices. In general, transferred-arc devices have been interfaced with open-bath furnaces in which melting or smelting processes are carried out, and non-transferred-arc devices have normally been applied to shaft furnaces.

Plasma melting can raise temperatures very rapidly and is thus more energy efficient than conventional melting technologies, for example, in non-BF applications. Plasma furnaces for melting aluminum are reported to impart heat 60-percent faster than conventional high-rate melters. Because of the rapid heat transfer in a plasma furnace, melting is also rapid. In aluminum making, the energy consumption rate is as low as 0.44 kWh/kg of aluminum compared to 0.76 kWh/kg of aluminum for induction melting. These data all are for non-steel application.

The following benefits are reported for plasma BFs compared to conventional BFs:

- Reduced energy use
- Minimized metal loss from oxidation and contamination
- Carbon consumption reduced by 50 percent

(8) Emerging Technologies for Steelmaking Shops

The subsections below describe the following emerging technologies to reduce energy use and CO_2 emissions in the steel making shop: sensible heat recovery from EAF off gas, electrochemical de-zincing of steel scrap, continuous horizontal sidewall scrap charging, scrap-based steelmaking using predominantly primary energy, ECOARC, BOF and EAF post-combustion optimization using CFD modeling, laser-based optimization of EAF post combustion, model-based steel temperature measurement for EAFs, real-time measurement of melt constituents, and the continuous EAF steelmaking technology.

(9) Sensible Heat Recovery from Electric Arc Furnace Off Gas

Because almost 70 percent of the energy losses in EAF steelmaking are associated with the off gas, through which approximately 15.5 percent of EAF energy inputs are lost as sensible heat, heat recovery could save substantial energy in EAFs. Combined with uncombusted CO that subsequently burns in the post-combustion chamber, the total thermal energy that can be recovered is more than 25 percent of EAF energy inputs. This is the amount of off-gas energy needed for viable off-gas heat recovery.

Despite the significant potential benefits, EAF off-gas heat recovery is not commonly practiced, in part because of the harsh environment in the fume system and the on-off batch nature of the process.

For a 140 t/h EAF, the EAF off-gas heat recovery technology would eliminate boiler-equivalent CO_2 emissions of almost 112,500 t CO_2/year (with coal firing) or 57,000 t CO_2/year (with natural gas firing). It is also possible to add a second stage in which the off-gas temperature is reduced from ~600°C to ~200°C with a waste heat boiler instead of the standard off-gas quench. The combined heat recovery using both the evaporative cooling system and the waste heat boiler is 75 to 80 percent of the total energy content in the waste gas, which corresponds to approximately 20 percent of primary energy input to EAF process. In cases where there is insufficient demand for steam from the EAF heat recovery, an organic rankine cycle turbine can be used for power generation. Organic rankine cycle generators are becoming commonplace in industrial heat recovery applications. They typically operate at approximately 20-percent efficiency and could be expected to generate about 4MW of electric power from an average-sized EAF. This translates to 24,000 megawatt hour (MWh)/year of electrical energy, a 7.5-percent savings in EAF net electrical energy usage.

The Goodfellow Expert Furnace System Optimization Process (Goodfellow EFSOP®) is a Tenova GmbH dynamic control and optimization system for EAFs, which is based on real-time measurements of off-gas composition. The system uses state-of-the-art off-gas analysis combined with process data acquisition and real-time closed loop control to optimize EAF operation. When EFSOP is combined with off-gas heat recovery, depending on the specific operating practice, direct and indirect CO_2 savings can increase by 2 to 5 times, or 40,000 to 140,000 t CO_2 annually for a 1Mt/year EAF .

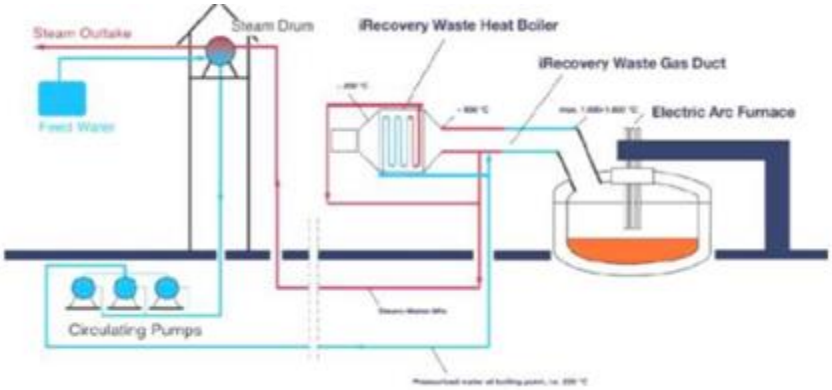


Figure 34. Schene of two-stage heat recovery for an EAF steelmaking by Tenova GmbH

The following benefits are reported for sensible heat recovery from EAF off gases compared to conventional EAF production:

- Reduced energy use for steam and power generation; 75- to 80-percent recovery of total energy content in the waste gas heat using both the evaporative cooling system and waste heat boiler, which equals approximately 20 percent of EAF primary energy input
- For a 140 t/h EAF, it eliminates boiler-equivalent CO_2 emissions of almost 112,500 t/year (with coal firing) or 57,000 t/year (with natural gas firing)

(10) New Scrap-Based Steelmaking Process Using Predominantly Primary Energy

Electricity is the main type of energy used in EAFs. The primary energy source is first converted to heat in a power plant; producing electrical energy is the next step. Like all conversions, these two processes entail losses whose amount is determined by the efficiency of the power plant. In an above-average power plant, this efficiency is approximately 40 to 42 percent. The electrical energy produced is transported to the EAF, with further losses incurred during transport, and then converted back to heat for steelmaking. Thus, almost two-thirds of the original primary energy is lost on the conversion route from source to EAF which makes use of on-site primary energy in the form of heat a preferable strategy for EAF.

A counter-current reactor should allow efficient use of primary energy (e.g. coal) in the scrap heating and melting steps. In such a reactor, scrap is continuously charged at the top and transformed to the liquid state with tapping temperature above what can be achieved by combustion of fossil fuels with oxygen because it is physically impossible to significantly superheat the melt in the presence of solid material. Thus, superheating occurs in a separate vessel using electricity. Thus, whereas the conventional EAF separates melting and heating in terms of time, these steps are separated spatially in the primary-energy melting process. The superheating vessel is an EAF with a power requirement comparable to that of a ladle furnace.

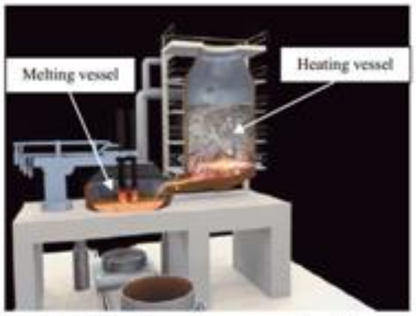


Figure 35. Schematic of the primary energy melter

The following benefits are claimed by SMS Demag GmbH for the use of primary energy in the heating and melting of scrap compared to conventional EAF production:

- Approximately 32-percent reduction of primary energy intensity for liquid steel production
- Depending on the CO_2 emissions of the electricity grid, significant reduction in CO_2 emissions

(11) In-Situ Real-Time Measurement of Melt Constituents

The proper composition of the melt constituents is a key factor in producing metals such as steel. The metal composition can only be controlled while the metal is molten. Therefore, in current practice, small samples of the molten material are removed and analyzed off line. This approach is expensive and time consuming, leading to excessive processing, quality control difficulties, and increased energy use and pollutant emissions.

Approximately 3 percent of all steel produced is downgraded or scrapped and that 50 percent of the downgraded or scrapped material needs complete rework. In-line measurements and closed-loop control can be a key to eliminating this waste.

A new technology developed by the Energy Research Company employs a laser-induced breakdown spectroscopic (LIBS) technique to measure, in-situ and in real-time, the constituents of the melt in a process furnace. A probe is placed inside the melt, and a laser is fired repetitively through a fiberoptic cable and through the probe. A small amount of melt at the probe tip absorbs the laser light, producing temperatures sufficiently high to heat and vaporize the melt sample into a gaseous plasma state. The resulting plasma emits a signal that is detected and sent to a spectrometer. This signal is spectrally resolved to uniquely identify the elements in the melt and the concentration of each element present.

The following benefits can be achieved by in-situ real-time measurement of melt constituents compared to steel production without this feature:

- Energy savings and CO_2 reductions because of reduction of downgraded or scrapped material
- Increased production and tighter compositional tolerances

(12) Injection of Plastic Waste in Electric Arc Furnaces

EAF steelmaking uses carbon-based materials as slag foaming agents. Depending on cost and availability, anthracite and metallurgical coke are often used as injection materials. Because of increasing energy prices and GHG emissions, alternative carbon sources are gaining attention as replacements for conventional materials. Waste materials such as high-density polyethylene plastics can react with gas and in slag phases resulting in de-volatilization, combustion, and iron oxide reduction reactions. The addition of waste plastics in EAF steelmaking has been studied in detail by The University of New South Wales and OneSteel with the goal of developing a method for EAFs to use blends of different proportions of rubber/ high-density polyethylene plastics and coke as a slag foaming agent.

A prototype scale process was able to replace 30 percent of the coke and coal with polyethylene waste plastic. This new process has demonstrated the ability to accelerate the slag-foaming process at the top of the melt, thereby saving energy. Consequently, a higher productivity is achieved. In 2007, OneSteel carried out commercial trials at its Rooty Hill facility in Australia. The first trials confirmed the speed-up of the slag foaming process with reduced electricity use. The tap-to-tap time was also reduced. The technology is planned to be implemented and further developed at the OneSteel Laverton facility.

Sahajwalla also investigated the combustion efficiencies of blends of metallurgical coke with plastics for EAF steelmaking. Laboratory tests for coke-plastic blends indicated higher combustion efficiencies compared to coke.

The following benefits can be achieved by injecting waste plastics in EAFs compared to using only coal:

- Estimated energy savings of around 12 kWh/t of plastic charge
- Reduced CO_2 emissions
- Increased productivity by reducing tap-to-tap time
- Reduced landfilling of plastic waste

(13) Use of Waste Tires in Electric Arc Furnaces

Steel making in an electric arc furnace is based on the principle of subjecting scrap metal to a high temperature (1,650 °C) for about 45 minutes until the metal becomes molten. An electric arc (temperature greater than 15,00 °C) provides the gradual rise in temperature. Normally in an EAF furnace, approximately 3.3t of lime and 1.15t of carbon in the form of anthracite and coke are added for every 100 t of scrap metal.

Rubber tires contain a large amount of carbon and energy and are available at lower costs than other potential alternative fuels. Additionally, the ever-increasing use of tires poses serious disposal problems in landfills because they do not biodegrade. Tires are generally disposed of in landfills and by incineration and to some extent co-processing in cement kilns; however, landfilling and incineration are becoming unattractive because of diminishing landfill space and for legislative reasons. Scrap tires make a good carbon source for EAF steel melting. The tires are added to the EAF as a source of chemical energy, replacing coal or coke. The carbon and hydrogen in the tires provide fuel energy, and the steel belts and beads become part of the material in the furnace. Oxygen is injected into the furnaces while the tires are burning so that combustion is clean and complete. The tires are completely consumed in the process. Contrary to popular belief, there is no increase in emissions from burning tires in an EAF. A 9-kg passenger tire has a fuel value of approximately 332 MJ. Tires have a higher heating value than that of coal and coke on a per-weight basis. Two or more passenger tires can be added per tonne of steel. Tire disposal fees that steel plants may receive for tires they burn can also result in a significant revenue per tonne of steel. Scrap tires contain 1.5 percent sulfur, which compares favorably with the sulfur content of most coal and coke. When scrap tires are used in the EAF, they do not cause any noticeable change in steel chemistry other than an increase in carbon if desired.

Under experimental conditions, Zaharia showed that most of the rubber/coke blends had higher combustion efficiencies than those of constituent coke in an EAF. An industrial trial of using scrap tires in EAF, carried out by Joulazadeh at Esfahan Steel Co. in Iran, showed that coke consumption reduced from 18.0 kg/t steel to zero and electricity consumption decreased from 448 to 388 kWh/t. The study also found that the amounts of gaseous pollutants released, such as CO, NOx, and SO_2, were far lower than the permitted limits.

The following benefits can be achieved by injecting waste tires in an EAF compared to injecting coal:

- Reduced coke and/or coal consumption
- Reduced CO_2 emissions
- Reduced landfilling of waste tires

Emerging Rolling and Finishing Technologies

The subsections below describe the following emerging technologies that save energy and reduce CO_2 emissions in the rolling and finishing phases of steelmaking: oxygen enrichment of combustion air combined with use of low-calorific gases, scale-free steel reheating, thermochemical recuperation for reheating furnaces, the hot strip mill model, continuous burn out measurement for management of reheating furnaces, oxygen-rich furnace system for reduced CO_2 and NOx emissions, HotEye® steel surface inspection, and oscillating combustion for NOx emissions reduction.

(1) High-Temperature Membrane Module for Oxygen Enrichment of Combustion Air for Fuel-Fired Industrial Furnaces

Industrial furnaces usually are operated with high-calorific gases (e.g., natural gas, converter gas). If these gases are replaced by low-calorific gases (e.g., biogas), then the flame temperature lowers. If the combustion air is replaced by oxygen, then the flame temperature can be increased to levels of combustion that are possible with high-calorific gases.

The cost-efficient production of oxygen is crucial to this technique. In a project supported by the German Federal Foundation for the Environment (Deutsche Bundesstiftung Umwelt), ceramic membranes were developed in which oxygen is extracted from air with the help of waste heat from the furnaces. This project demonstrated that the necessary furnace chamber temperature can be achieved with low-calorific gases and oxygen.

The following benefits can be achieved by the scalable high-temperature membrane modules for oxygen enrichment of combustion air in fuel-fired industrial furnaces, compared to use of high-calorific gases:

- Reduced CO_2 emissions (because biogas is considered carbon neutral)
- Use of waste heat from the furnaces

(2) Thermochemical Recuperation for Steel Reheating Furnaces

The conventional method for improving the efficiency of steel reheating furnaces is to preheat the ambient combustion air by recovering a fraction of the sensible heat in the flue gases leaving the furnace. This is typically accomplished by the use of metallic recuperators (air heat exchangers). Although recuperation increases reheating furnace efficiencies, there is still substantial opportunity to reduce fuel consumption of continuous reheat furnaces, including those equipped with recuperators.

One approach for utilizing the energy contained in waste heat is thermochemical recuperation. This new technique recovers sensible heat in the exhaust gas from an industrial process, furnace, or engine. That heat is then used to transform the hydrocarbon fuel into a re-formed fuel with a higher calorific heat content; this re-formed fuel is used for process heating. The technology has been demonstrated in a number of applications but has not yet been evaluated and developed for commercial adoption. U.S. DOE is supporting a project lead by the Gas Technology Institute to validate the technical feasibility of the thermochemical recuperation concept as well as its business viability, including identification of technical, scale-up, and processing concerns.

In the first phase of the project, the Gas Technology Institute licensed simulation software that can model heat transfer and chemical reactions along with computational fluid dynamics. The evaluation focused on energy-efficiency improvements and cost benefits. Technical information developed during the first phase is being used to design, fabricate, and iteratively evaluate performance metrics in a bench-scale thermochemical recuperation unit at the Gas Technology Institute's combustion laboratory. The results will then be used for engineering design, construction, and retrofitting of a full-scale thermochemical recuperation system for prototype field tests on a steel reheating furnace.

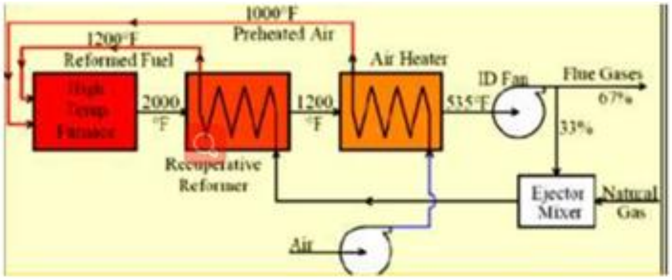


Figure 36. Thermochemical recuperation concept

The following potential benefits could be achieved by thermochemical recuperation compared to conventional reheating techniques:

- Net reduction in continuous reheating furnace fuel use because the energy content of the fuel can be increased by more than 25 percent when the original source fuel is natural gas

- Proportional reduction in CO_2 emissions
- Reduced NOx emissions

(3) Oxygen-rich Furnace System for reduced CO and NO emissions

Furnaces in the steel industry are one major consumer of fossil fuels. Hence, they are also key CO_2 emitters. A project was funded by the DOE/ AISI TR Program at Queen's University in Canada. The aim of the project was to develop and test the combination of a low NO_x-burner with oxygen enriched combustion air.

Normally two streams are injected in reheating furnaces, natural gas and air. In this project a third stream was added to introduce oxygen into the furnace. Therefore, the furnace control system needed to be adapted in order to deal with three streams instead of two streams. A PC-based controller and oxygen valve train were used to monitor and regulate the flow of oxygen based on a flow sensing device, limiting switches and relays. The burner was installed in a pilot reheat furnace and tested within a range of operating configurations.

The burner was tested by maintaining a constant target temperature of 1100°C corresponding to firing rates of 325–365 kW at zero percent oxygen enrichment, depending on the stack oxygen concentration (excess oxidant). At 100 percent oxygen enrichment, firing rates in the range of 200–220 kW were required to maintain furnace temperature. This represents potential savings of 40–45 percent in fuel usage and a corresponding reduction in CO_2 emissions. Oxygen enrichment had little effect on NO_X emission up to an enrichment level of about 60 percent. At higher oxygen enrichment, emission levels decreased but not to zero because of nitrogen incorporated with the natural gas.

Oxygen enrichment leads to different combustion environment with significantly larger proportions of CO_2 and H_2O along with the excess oxygen commonly present in combustion systems. Hence, scale morphology was tested at samples of the 5 steel grades. The results showed that scale habit, intactness, and adhesion were not mainly affected by the stack oxygen and oxygen enrichment levels but by the steel grade. The steel scaling rates observed with oxygen enriched combustion conditions was slightly higher, but this effect was not large. A modification of an ultra-low NO_x burner which can provide O_2 enriched combustion was installed in a pilot reheating furnace in a steel plant in Canada.

Following benefits can be achieved by applying oxygen enrichment technology in reheating furnaces compared to conventional operation of reheating furnaces:

- Potential savings of 40–45 percent in fuel usage and a corresponding reduction in CO_2 emissions
- Reduced NO_x emissions

(4) Nitrogen Oxide Emission Reduction by Oscillating Combustion

Industrial furnaces are major consumers of fossil fuels and therefore key CO_2 emitters. If they are fired with preheated air, it can reduce CO_2 emissions but NO_x emissions will rise. A switch to oxygen injection can improve energy efficiency and reduce NO_x emissions, but its application is more cost intensive and might not always be compatible with the material being heated. By retrofitting oscillating combustion, fuel-rich and fuel-lean zones are created within the furnaces.

Thereby NO_x emissions are reduced and furnace efficiency is increased for both air- and oxygen fired furnaces.

Oscillating Combustion is a retrofit technology that involves the forced oscillation of the fuel flow rate to a furnace. Its implementation requires that a valve is installed on the fuel supply line of each burner. The oscillating valve must be able to rapidly open and close at the frequencies, amplitudes, and duty cycles needed to optimize the heat transfer and/or reduce the NO_x emissions. Furthermore a controller must also be installed to drive all the valves on a furnace (or for each zone of the furnace) to keep the valves in proper synchronization and phasing. No modification of the burner or the furnace is necessary.

It has been shown that oscillating combustion can produce substantial increases in heat transfer and reductions in NO_x emissions on many types of industrial burners. Heat transfer increases of up to 13 percent and NO_x reductions of 31 percent to 67 percent were recorded. The highest levels of NO_x emissions reduction were achieved with burners that use a nozzle-mixing approach and/or preheated or oxygen enriched combustion air, while the highest levels of heat transfer increase were achieved with burners using ambient air, although the heat transfer increase was still significant (up to 6 percent) with burners using preheated combustion. Oscillating combustion was not found suitable for burners using staging or high momentum approaches. Oscillating combustion has been field tested in many types of industrial furnaces using conventional burners.

Following benefits can be achieved by applying oscillating combustion:

- Saving of up to 5 percent of fuel use by the furnace
- Improved heat transfer by up to 13 percent
- Increased productivity by 5 percent or more
- Reduced NOx emissions by up to 75 percent
- Simple retrofit that does not require modification of burner or furnace

Carbon Capture and Storage Technologies for the Iron and Steel industry

In the iron and steel sector, the main sources of CO_2 emissions are power production, iron ore reduction in either a BF or a DRI plant, and coke and sinter production. Selection of carbon capture equipment will depend on factors including CO_2 capture rate, possible requirements for secondary gas treatment, energy consumption, reliability, and operational and capital costs. The BF production process can be equipped with CO_2 capture. There are also several alternatives to BF technology that have lower carbon emissions, including advanced smelting reduction technologies, e.g., HIsarna and FINEX, and DRI technology. Research is under way to identify the most energy-efficient capture technique for removing CO_2 from the BF gas recycling system. Biomass-based DRI processes are also under development and could become an important low carbon iron production pathway.

Unlike in the power generation sector, in the steel industry much of the generation of CO_2 is related to the reduction of the iron oxides that constitute iron ore. Oxyfuel combustion and pre- or post-combustion capture chemical looping do not mean much in a steel industry context where there is neither combustion nor oxidation except very locally inside the reactors.

ULCOS is currently the largest initiative to reduce CO_2 emissions from the iron and steel industry, including through the use of carbon capture and storage. ULCOS is funded roughly equally by industry partners and the European Union. Despite the evidence of significant interest in carbon capture and storage (CCS) in the iron and steel sector, no large scale demonstration plants have yet been developed.

(1) Top-Gas Recycling in Blast Furnaces, with Carbon Capture and Storage

Perhaps the most advanced potential CCS technology for the iron and steel sector is the top-gas recycling BF (TGR-BF). The TGR-BF relies on separation of the off gases so that the useful components can be recycled back into the furnace and used as reducing agents. This reduces the amount of coke needed in the furnace. In addition, the concept of injecting oxygen into the furnace instead of preheated air removes unwanted nitrogen from the off gas, which will be rich in CO (40 to 50 percent by volume), facilitating CCS. To experimentally test this concept, a gas separation plant was constructed next to LKAB's Experimental BF in Luleå, Sweden. At the experimental BF, facilities were installed to operate with pure oxygen and with re-injection of CO gas. The combination of the modified BF and the gas separation plant was successfully tested in 2007. Plans are currently being developed to test this principle in a commercial-scale BF.

A number of approaches to carbon capture have the potential to be deployed in iron and steel making, depending on the production process being used. These include chemical adsorption technologies such as amine scrubbing, physical adsorption technologies such as pressure swing adsorption and vacuum pressure swing adsorption, and cryogenics. Detailed studies, carried out under the ULCOS project, have shown that the most effective approach in any circumstance will depend on a number of factors, including the concentration of CO_2 in the stream of gas being treated. TGR-BF can be retrofitted to conventional BFs although major modifications to the furnace may be required.

At the levels of concentration found in TGR-BF, physical adsorption technologies are likely to be most effective in terms of technical performance and operating and capital costs. Although pressure swing and vacuum swing adsorption have low energy requirements, they are only able to produce gases with CO_2 concentrations of approximately 80 and 88 percent respectively. Therefore, additional treatment may be required to remove impurities from the resultant gas stream, which will increase cost and energy usage.

The relative advantages of individual technologies will vary over time. For example, the amine washing considered in the ULCOS program is based on the present state of the art of this fairly common technology, i.e., on the use of commercial MDEA amines that currently require 3.2 GJ/t CO_2 to restore the sorbent. The Japanese COURSE 50 national program aims to reduce the energy needed for carbon capture to 1.8 GJ/t CO_2, to make the process work at lower temperatures, and to use wasted heat.

The following benefits are claimed for TGR-BF compared to conventional BF production:

- Reduction of up to 30 percent in coke consumption compared to what is needed in a conventional air-blown BF.
- Estimated emissions reduction of approximately 35 percent compared to emissions from a benchmark steel mill. With CO_2 capture from an additional stack, for example from a

sinter plant, estimated emission reductions of 75 percent.
- Somewhat smaller overall CO_2 emissions reduction than what is mentioned above because reduced BF gas export needs to be compensated for, and a large amount of electricity is required to produce high-purity oxygen

(2) Advanced Direct Reduction with Carbon Capture and Storage (ULCORED)

Production of DRI entails exposing iron ore (in the form of lumps or pellets) to a reducing gas that is produced predominantly from natural gas. The reduced iron is in a solid state, and electric energy is required to melt it in an EAF. Currently, this process is more expensive than reducing the ore in a conventional BF and it also requires better-quality iron ore than is needed for a BF. The amount of electricity required for melting DRI means this EAF process also uses more energy than a BF. However, EAFs have the advantage of eliminating the need for the coke ovens on which a BF depends. As part of the ULCOS project, a new DRI process, ULCORED, was designed by a team led by LKAB, Voestalpine, and MEFOS. This process reduces the amount of natural gas needed to produce DRI. This is partly achieved by replacing the traditional technology, reforming, by partial oxidation of the natural gas. This substitution will substantially reduce capital costs. In the new layout there will be a single source of CO_2, which will be sufficiently clean for geological storage.

During the past decade, a small number of DRI installations have been combined with coal gasification installations and the coal-derived syngas used as the reducing gas. This process may be particularly important for countries that have limited gas supplies but large coal reserves, such as India, China, and South Africa. CO_2 from the gasification process can be captured using precombustion technologies. ULCORED could also be used with syngas from coal and biomass, and it could be used to produce CO_2-free hydrogen for use in other parts of a steel plant.

The following benefits are claimed for use of ULCORED compared to conventional DRI production:
- Estimated reduction in energy use of 20 percent compared to state-of-the-art DR processes
- Only one stream of CO_2 for compression and storage
- Flexibility to make CO_2-free hydrogen for other users

(3) HIsarna with Carbon Capture and Storage

HIsarna is a smelting reduction process based on bath-smelting. It combines coal preheating and partial pyrolysis in a reactor, a cyclone for ore melting, and a smelter vessel for final ore reduction and iron production. This technology requires significantly less coal than conventional production and thus reduces CO_2 emissions. The process allows partial replacement of coal with biomass, natural gas or even hydrogen. The three separate technologies associated with HIsarna have been proven independently at a small scale.

The HIsarna process offers a longer-term strategy for reducing CO_2 from the iron and steel industry. HIsarna uses pure oxygen and generates an off gas that is almost ready for storage. It is based on the combination of a hot cyclone developed by Corus and a bath smelter called HIsarna licensed by Rio Tinto. It incorporates some of the technology of the HIsmelt process. The HIsarna process is an alternative for the BF/BOF steelmaking route. As a result, it can reduceCO_2 emissions from steel production by 20 percent. In combination with CCS, the process can reduce CO_2

emissions by 80 percent . Capture technologies for HIsarna process are pressure swing adsorption/ vacuum pressure swing adsorption.

The following benefits are claimed for HIsarna compared to conventional BF production:

- Lower coal consumption
- Reduction of 20 percent in CO_2 emissions, or 80 percent if combined with CCS
- Allows partial replacement of coal with biomass, natural gas, or hydrogen

(4) Post-combustion Carbon Capture Using Chemical Absorption Technologies

Chemical absorption (amine scrubbing) has been used to separate CO_2 in chemical industry exhaust streams. Post-combustion carbon capture takes advantage of this commercially mature technology and applies a common solvent, monoethanolamine, for CO_2 scrubbing. Because of the high cost of this solvent, it has to be regenerated and re-used, an energy-consuming process that results in additional CO_2 emissions. SO_2, NO_2, and oxygen play an important role in solvent degradation mechanisms. Therefore, the SO_2, NOx, and particulate matter concentrations in flue gases need to be reduced to a minimum before the flue gases go through the solvent scrubbing CO_2 capture system.

Chemical absorption CO_2 capture is generally considered a short-term technology. A major limitation of capturing CO_2 directly from BF gas is that less than 50 percent of the total carbon contained in the BF gas is captured because about half of the carbon is in the form of CO. In addition, the capture of CO_2 directly from BF gas is deemed more expensive compared to other options. A potentially feasible technology for BFs in the short or medium term is to capture CO_2 after CO in the BF gas is converted to CO_2 via a shift reaction, enabling a higher carbon removal rate (85 to 99.5 percent of the carbon in the BF gas). After shift reaction and CO_2 removal, the BF gas is hydrogen rich. The main advantage of the shift reaction is that higher power generation efficiency can be achieved when hydrogen-rich BF gases are used in a power plant. The major disadvantage is that the power plant using the BF gas might require important modifications in the gas turbines.

In the shift reactor, CO reacts with steam: $CO + H_2O \rightarrow CO_2 + H_2$. The pressure loss in the shift reactor amounts to 1 bar. The shift reaction is basically exothermic. The reaction enthalpy is about 0.92 GJ/t of CO_2 generated. The shift reactor needs high-temperature steam (350ºC). Steam is recovered from the off-gas of the second reactor, and some of the residual heat is used to preheat the feedstock and steam for the first reactor. Surplus steam may be available for other uses.

The following benefits can be achieved by amine scrubbing CCS compared to production without this technology:

- CO_2 emissions reduced by less than 50 percent of the total carbon contained in the BF gas without shift reaction technology, and by 85 to 99.5 percent of the carbon in the BF gas with shift reaction

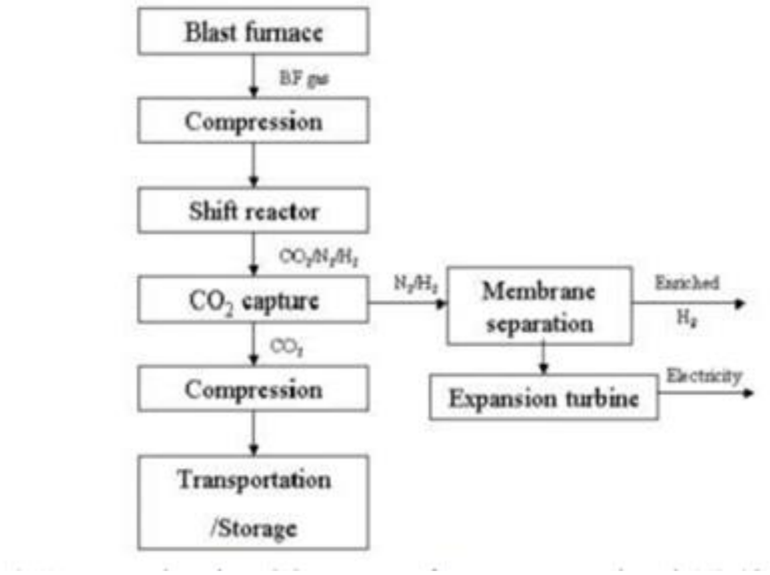


Figure 37. Post-combustion CO_2 capture from a conventional BF

(5) Integrating Steel Production with Mineral Sequestration

Mineral sequestration, the disposal of CO_2 in the form of benign solid carbonate, is a permanent and safe method of CO_2 disposal with virtually unlimited capacity. This method of CO_2 disposal could greatly benefit from collaboration with the steel industry as the hydrometallurgical processing of the mineral ore (peridotite rock) results in the generation of virtually pure iron oxides. This would provide new sources of iron oxide from peridotite ores and would sequester CO_2 from the BF and other combustion operations including power plants. The steel industry is accustomed to pre-processing iron ores prior to introducing them to the BF. If the gangue materials could be used to chemically bind CO_2, this would develop a niche market for the steel industry, allowing it to dispose of its own CO_2.

U.S. DOE/AISI Technology Roadmap Program supported a project led by Columbia University to develop a combination iron reduction and carbon sequestration plant that will use serpentine ores as the source of iron and dispose of the iron-industry CO_2 (as well as additional CO_2 from other sources) in the mineral tailings that remain at the end of the iron reduction process. Using the same ore-processing steps for carbon sequestration and iron ore production increases the value of the carbon sequestration process and reduces the cost of sequestration.

A viable mineral carbon sequestration process utilizing serpentine has never been demonstrated because of slow reaction times with CO_2 in aqueous solutions. Experiments were performed exploring the catalytic effect that sodium chloride and ammonium chloride might have on serpentine dissolution, which is the rate-limiting step in the overall carbonation process. It was found that although initial dissolution rates appear to be enhanced by the presence of the salts, long-term dissolution rates remain unaffected; therefore, these salts will not help lower the costs of a mineral carbonation process. More research is needed to develop a viable carbon sequestration technology using serpentine or similar minerals.

The following benefits could be achieved by integrating steel production with mineral sequestration:

- Significant reduction of CO_2 emissions
- Creation of a carbon sink within the steel industry that could be sold as CO_2 credits to other industries
- Production of valuable iron oxide from peridotite ores

4.6. Real reduction ability analysis of Manufacturing-ethanol

Table 65. Real reduction ability of Manufacturing-ethanol industry

Technology	Characteristics	Application	Application Part	Rate of mitigation
Siftek™ Membrane	Hydrophilic polyimide	New Plants	Siftek™ Drying System	3.8%
	Temperature stable		Siftek™ Dewatering System	43%
	Solvent-resistant	Retrofit Plants	Siftek™ Drying System	2.6%
	Patented formulation		Siftek™ Dewatering System	28%

Notes: The real reduction analysis is based on corn-based ethanol production.

4.6.1. Introduction Canadian ethanol industry

The idea of using ethanol as a motor fuel dates back to the early 1800s. In 1826, Samuel Morey developed an engine that ran on ethanol and turpentine. In 1860, the German engine inventor, Nicholas Otto, used ethanol as the fuel in one of his engines. Moreover, in 1908, Henry Ford produced his Model T. car as a flexible fuel vehicle, running on ethanol, gasoline, or a combination of the two (U.S. Department of Energy 2003). But ethanol did not become the fuel used in automobiles because a new fuel, gasoline, emerged dominant in the early twentieth century. Its lower octane rating suited the materials then available for engine construction. There was also a growing, seemingly unlimited supply of low-cost petroleum from oil field discoveries (Canadian Renewable Fuels Association).

The mid 1970`s were the starting point of a growing ethanol industry in Brazil and the United States of America. These governments started to support the development of the ethanol industry as an alternative to the dramatic escalation of imported crude oil prices (Gilmour 1986). Later, environmental concerns such as climate change (marked by the Kyoto Protocol adoption in 1997) and pollution due to gasoline octane enhancers (lead, MTT) added themselves to the reasons of public support to the development of the ethanol industry (Gilmour 1986). In the case of Canada, federal support for the ethanol industry started mainly because of climate change commitments (Ethanol Expansion Program is part of the Climate Change Plan for Canada, which was conceived in order to meet the Kyoto Protocol engagements). These days, another important reason for governments to support fuel ethanol is the overproduction in coarse grains markets. Finding additional markets for the surplus of coarse grains is viewed as a solution to the dependence on international markets or to the increasing financial support to agriculture. The objective of this paper is to provide an overview of today’s situation of the ethanol industry.

Ethanol or ethyl alcohol is a two-carbon alcohol produced either chemically from the hydration of ethylene (a petrochemical feedstock) or biologically by the fermentation of carbohydrate materials, such as grains. No chemically produced ethanol is made in Canada since Commercial Alcohols closed its facility in Varennes, QC, in 1991 (Cheminfo Services Inc., (S&T)2 Consultants Inc. and Cemcorp Ltd, 2000).

Based on final use, there are two main categories of biologically obtained ethanol: fuel ethanol (anhydrous) and industrial ethanol (used in the production of vinegar, food extracts, pharmaceutical products, cosmetics, solvents and beverages). Fuel ethanol is traditionally used as 6 a gasoline extender and as an additive (oxygenates octane enhancer). Examples of combinations of gasoline and ethanol are the so-called E10 (10% ethanol and 90% gasoline) and E85 (85% ethanol and 15% gasoline). The ethanol blend E10 is called gasohol. Two other potential uses of fuel ethanol are i) in fuel cells (as fuel on board the vehicle, which is necessary to the formation of hydrogen) and ii) as diesel extender. A blend of diesel fuel, ethanol (7.5%) and fuel additives known as e-diesel was demonstrated in Winnipeg (Government of Manitoba 2002b).

Both industrial and fuel ethanol can be produced from two main categories of feedstock: grains and cellulose. Ethanol is obtained from grains by fermentation of sugars (starch) and from cellulose by conversion of the cellulose into sugars and their fermentation afterwards. Grainbased ethanol is mainly obtained from sugar cane, corn, wheat or barley while the cellulosebased ethanol is derived from waste bio-mass (ex: straw) or crops/trees specifically grown as feedstock (ex: switch grass). In Canada, the grain-based production process dominates, representing 92% of the actual production capacity. Research is presently conducted to make the cellulose-based production process economically viable (Iogen Corporation is the main Canadian research centre). Because of its environmentally friendly production process (no fossil fuel is used), cellulose-based ethanol obtained by Iogen Corporation is also called bioethanol or EcoEthanol, the latter being the trade mark of Iogen Corporation (Iogen Corporation 2004).

There are two general categories of grain ethanol production: dry milling and wet milling. In the case of dry milling production process, the most important market value is obtained from ethanol, while in wet milling the co-products (gluten, especially) play an equally important role, their market value being superior to those obtained in dry milling. Because ethanol is obtained from the starch component of a grain and the co-products mainly from the protein component, the feedstock used in dry milling generally has high starch content and low protein content while those used in wet milling have low starch content and high protein content.

The co-products of a dry milling ethanol plant are carbon dioxide (CO_2) and distillers grains (DG). Distillers grains can be used wet (WDG) or dried (DDG) and are almost exclusively used as an ingredient in animal rations. In large plants (more than 50 million litres per year) the collection and selling of the carbon dioxide can be economical. Two of the co-products of wet milling plants are gluten and a low protein animal feed (Cheminfo Services Inc. et al. 2000).

Production

The ethanol industry has consolidated leaving only the bigger players and those that remain are producing at capacity. A complete list of the plants can be found on the website of the Canadian Renewable Fuels Association website (URL: http://ricanada.org/industry/industry-map/). Canadian ethanol plants for the most part have operated at maximum capacity since 2009. Demand for fuel ethanol has generally exceeded domestic supply due to the implementation of provincial mandates and the federal blends mandates. The availability of the federal and provincial support programs has been sufficient for the plants to operate positive cash flows despite spikes in feedstock prices and competition from US imports.

The cellulosic plant ENERKEM was not included the domestic production numbers due to the fact that it is not conventional ethanol; so also not included in the capacity. In addition, the plant is not currently producing ethanol from municipal waste but instead is producing methanol because the economics are better.

A plant closure in 2015 reduced nameplate production capacity, however, increased efficiencies in the other plants will help lift production in 2016 to an estimated 1,750 million liters, 1.4 percent above 2015 production levels. Production in 2017 is expected to remain level with that of 2016 due to no new plants coming on line. Domestic production capacity will likely remain at 1.775 billion liters unless economics change substantially. Canada, unlike the United States has not reached a domestic production capacity that makes it possible to meet its blend mandates with domestic production alone and therefore will continue to import the balance.

As domestic production has increased, so has the production of co-products. Corn oil production has not followed the trend in the United States due in large part to the fact that Canada Feed Regulations require that the Dried Distillers Grains (DDGs) have a minimum amount of energy content that requires more oil remain in the DDGs.

Feedstock choice for ethanol plants has been driven by the availability of feedstock. Corn and wheat are the main feedstock for bioethanol production in Canada. Feedstock use figures are based on Post estimates, assuming plants use feedstocks grown in their vicinity. Ethanol plants in Ontario, Quebec and Manitoba process corn as it is available in the vicinity of the ethanol plants. Ethanol plants in Saskatchewan and Alberta process mostly feed wheat as there is limited corn production in those regions.

There has been an increasing interest in developing corn varieties that can be grown in Western Canada. As more corn varieties are developed with lower heat unit requirements, it is expected that corn use for ethanol production in Saskatchewan and perhaps Alberta will increase. There has also been increasing research on wheat varieties for industrial use. Currently, the need for high-yielding, low-protein wheat by the livestock industry and the bioethanol plants put the industries in conflict with each other when supplies of feed wheat are low. A large wheat crop is expected in 2016 (June 2016-July 31 2017) and therefore Post is assuming that higher supplies of feed wheat will be available this year compared to the previous year.

In 2016, it is estimated that Post estimates that 77 percent of the domestic production of domestic ethanol will be derived from corn, and 23 percent will be derived from wheat. Post forecasts that this will likely remain relatively stable throughout 2017. Post assumes based on harvest reports that there will be amble supplies of corn from the U.S. as well as domestic feed wheat will allow plants much flexibility.

Table 66. Canadian ethanol facilities

Plant Name	City	Province	Feedstock	Capacity (Mmly)	Status
Atlantec Bioenergy Corporation	Cornwall	Prince Edward Island	Energy beets	n/a	Demonstration Facility
Enerkem - Edmonton Waste-to-Biofuels Facility	Edmonton	Alberta	Post-sorted municipal solid waste	38	Under Construction
Enerkem Inc.	Sherbrooke	Quebec	Various feestocks	0.475	Demonstration Facility
Enerkem Inc.	Westbury	Quebec	Wood waste	5	Demonstration Facility
Enerkem Inc.	Varennes	Quebec	Sorted industrial, commercial and institutional waste	38	Proposed Demonstration Facility
GreenField Ethanol Inc.	Chatham	Ontario	Corn	195	Operational
GreenField Ethanol Inc.	Johnstown	Ontario	Corn	250	Operational
GreenField Ethanol Inc.	Tiverton	Ontario	Corn	27	Operational
GreenField Ethanol Inc.	Varennes	Quebec	Corn	175	Operational
Growing Power Hairy Hill	Hairy Hill	Alberta	Wheat	40	Operational
Husky Energy Inc.	Lloydminster	Saskatchewan	Wheat	130	Operational
Husky Energy Inc.	Minnedosa	Manitoba	Wheat and corn	130	Operational
IGPC Ethanol Inc.	Aylmer	Ontario	Corn	172	Operational
Kawartha Ethanol	Havelock	Ontario	Corn	100	Operational
NorAmera BioEnergy Corporation	Weyburn	Saskatchewan	Wheat	25	Operational
North West Bio-Energy Ltd.	Unity	Saskatchewan	Wheat	25	Operational
Permolex International, L.P.	Red Deer	Alberta	Wheat, wheat starch, corn, barley, rye & triticale	42	Operational
Pound-Maker Agventures Ltd.	Lanigan	Saskatchewan	Wheat	15	Operational
Suncor St. Clair Ethanol Plant	Sarnia	Ontario	corn	400	Operational
Terra Grain Fuels Inc.	Belle Plaine	Saskatchewan	Wheat	150	Operational
			Total Production	**1957.475**	

Consumption

A use mandate of 5 percent ethanol blended into the gasoline supply currently requires a 2.2 billion liters of ethanol. However, production and trade statistics indicate that the national average blend rate rose above the federally mandated level and was higher than most provincial mandates after 2012. Low corn prices contributed to low ethanol prices driving blend levels above the above the minimum federal (and most provincial) blend level requirements. Financial incentives encouraging "discretionary blending" (blending above required minimum levels) were strongest in 2013, but have since moderated mainly due the stronger U.S. dollar (increases the cost in importing feedstock (corn) and ethanol) and lower oil prices. In 2016 and 2017, blend levels for ethanol in gasoline are expected to remain at 6.0 percent.

Imports and Exports

Lower discretionary blending tends to impact ethanol imports negatively. Year to date trade data (January to May) under tariff lines 2207201210 and 22072109010 suggests that ethanol for fuel imports in 2016 will decrease slightly from 2015 import levels of 1,093 million liters. Imports in 2016 are expected to fall to 1,000 million liters due to decreased demand. The United States will remain the main market (close to 100 percent share) from which Canada imports its fuel ethanol. Imports for 2017 are forecast to remain at similar levels to 2016, assuming that there are no changes to the blend mandates and lower gasoline prices are forecast to persist.

Canada exports less than 200 thousand liters of ethanol fuel per year due to the fact that domestic production has not yet surpassed the amount required to the transportation cost, feedstock/operating costs make the delivered cost of Canadian ethanol in the U.S. too high to be competitive. Statistics Canada reports that in year 2015, Canada exported 104 thousand liters of fuel grade ethanol, with 63% of it going to the United States. The year to date trade data suggests that the volume exported in 2016 may increase slightly in 2016 over 2015 levels to reach 114 thousand liters. Exports in 2017 are forecast to remain at similar levels since there is no significant increase in production or decrease in demand that is expected to generate a significant surplus for export markets. Due to the North American Free Trade Agreement (NAFTA), there is no tariff on renewable fuels produced in the United States and imported into Canada. However, Canada does have a tariff on bioethanol imported from other countries such as Brazil ($0.05 per liter).

In terms of meeting standards, both corn and wheat ethanol plants in Canada do not have difficulty meeting the Canadian quality standard (CGSB) which is more restrictive than the ASTM standard used in the United States. As a result, Canadian ethanol does not have difficulties entering the United States. However, due to differences around minimum moisture content, not all US ethanol producers can meet the Canadian standard and remain price competitive which can prevent access to the Canadian market.

Ethanol Production in Saskatchewan

Ethanol production in Saskatchewan has been occurring since Poundmaker AgVentures completed its 10-million-litre facility in Lanigan in 1990. The provincial government directly subsidized the plant from 1991 to 1993 at approximately 40 cents per litre and also provided a tax exemption of 15 cents per litre through the early to mid-1990s. In 2000, the provincial government reinstated this exemption for all ethanol production in the province (Olar et al., 2004).

In the fall of 2006, two more plants opened in Weyburn (owned by NorAmera BioEnergy Corporation) and Lloydminster (owned by Husky Energy) with capacities of 25 million litres and 130 million litres, respectively. Despite the fact that these plants were only recently completed, the provincial government had contemplated investing in, or facilitating the expansion of an ethanol industry for several years. In 2002, the provincial government unveiled its Greenprint for Ethanol Production in Saskatchewan, a plan that was designed to vastly expand the province’s ethanol industry. The plan called for the industry to expand to 400 million litres per year of ethanol production in the next few years and suggested that 1 billion litres annually could be feasible (Government of Saskatchewan, 2002).

Since ethanol production is not currently cost-competitive with gasoline, the provincial government has suggested that it will facilitate industry expansion by providing tax exemptions on ethanol that is both locally produced and consumed. In addition, the government plans to create a local market by mandating that all gasoline sold in Saskatchewan contain 10% pure ethanol, to occur once provincial ethanol capacity is large enough to meet the demand thus created (around 130 million litres) (Government of Saskatchewan, 2002). It is anticipated that ethanol produced above this level will be exported to other jurisdictions in Canada and the U.S. A second component of the plan is to require that distributors buy 30% of their ethanol from “small” ethanol plants (25 million litres or less annually) in an effort to promote producer-owned facilities (Olar et al., 2004).

Producer-owned facilities are part of the province's plan to use ethanol as a vehicle to revitalize the rural economy, while at the same time benefiting the environment. The government's Greenprint suggests that ethanol plants will create up to 450 job opportunities both in terms of ethanol production and through feedlots that are often associated with ethanol production. In addition, the government has suggested that ethanol plants will create a new marketing alternative for producers (presumably at higher prices) who face low grain prices. In terms of the environment, the Greenprint suggests that ethanol offers numerous environmental benefits, most notably a reduction in GHG emissions and in compounds that contribute to smog (Government of Saskatchewan, 2002).

4.6.2. The benefits of developing the ethanol industry

Rural Economic Benefits

Ethanol brings new jobs, increased economic activity and higher incomes for farm families to rural Canada.

Ethanol is good for rural Canada. It benefits communities and residents by attracting investment, increasing farm incomes, and creating new jobs. The very first independent survey dedicated to measuring the economic impact of Canada's renewable fuels sector was conducted in May 2010 by Ottawa-based Doyletech Corporation. It found:

- 14,177 new direct and indirect jobs have been created to support construction of new production facilities and each year, as many as 1,038 new jobs are created to support ongoing operations.
- $2.949 billion has been generated in economic activity from plant construction and approximately $1.473 billion in economic activity is generated annually from these same facilities.
- A lone ethanol plant brings significant benefits to a rural community. The impact of even a single ethanol facility can supercharge a community's local economy.
- Local suppliers reap the rewards. The local economic impact is positive and builds outward. From the individual farmer who receives a better price and market security for his crops to the new plant, rural shopkeepers, suppliers, and businessmen, all receive a tangible economic boost.
- Communities benefit from new tax revenues. New plants mean municipalities have more money to invest in services and infrastructure.

Boosting Farm Income

While increases in crop prices are still relatively modest, they do translate into the most sustainable prospect for boosted farm incomes in years.

Farmers are getting fair prices. Farmers are now able to earn more than the cost of production, putting them into a net positive position. In addition to basic fairness, this turn of events will help combat distortions in global agricultural subsidies that hit both our own farmers and those in the developing world very hard.

- FACT: The Saskatchewan provincial government has suggested that increasing ethanol use will not only reduce greenhouse gas (GHG) emissions that result from transportation, but also increase farm income for primary producers and create jobs in rural areas, thus contributing to a revitalization of the rural economy.

Ethanol is creating new demand and new markets. Although only about 10% of corn is used for ethanol production in Canada, the rise in demand for renewable fuels creates promising new market options for farmers and the promotion of the domestic, value added agricultural industry. The emergence of $100+ oil in 2008 and ethanol-friendly policies of the Canadian government suggest that demand for renewable fuels is something farmers can rely on for the future.

- FACT: “The Government of Canada will invest up to $1.5 billion over nine years through the eco ENERGY for Biofuels program. The Government of Canada’s Economic Action Plan also dedicates funding to the Clean Energy Fund and the Green Infrastructure Fund to provide additional economic stimulus while promoting a cleaner, more sustainable energy future for Canadians.”
- FACT: Better corn prices do not significantly increase the cost of groceries. Grocery costs are driven much more by production, packaging, transportation and marketing costs than by grain costs.
- FACT: As of 2005 a box of Corn Flakes contained 7 cents worth of corn. Even if prices doubled, the cost of food would not be greatly impacted
- FACT: Renewable fuels production also provides a market for damaged or low-grade crops.

Environmental Benefits and Climate Change

Ethanol is a practical alternative energy source that can be used in vehicles right now and which both lowers GHG emissions and combats smog. If Canadians are going to succeed in combating climate change, we’re going to have to deal head-on with transportation fuels that generate large GHG emissions from our gasfuelled cars, trucks and other vehicles. Ethanol is the only practical, immediately available means to lower this impact.

- Ethanol cuts emissions from our cars. Ethanol reduces tailpipe carbon monoxide emissions by as much as 30%, toxic content by 13% (mass) and 21% (potency) and tailpipe fine particulate matter emissions by 50%.
- Ethanol lowers GHG’s. A new independent third party analysis of Canadian renewable fuel production conclusively confirms that based on a lifecycle assessment, Canadian produced ethanol and biodiesel significantly reduce greenhouse gas emissions. Based on feedstock, ethanol reduces GHGs by up to 62% and biodiesel by 99%. The 5% RFS alone will generate 4.2Mts fewer emissions – or the equivalent of removing one million cars from our nation’s highways.
- Ethanol replaces carcinogens in your fuel. Ethanol actually cuts down cancer-causing emissions such as benzene from our fuel. Ethanol is an oxygenate, a fuel additive that raises the octane level of gasoline, producing a motor fuel that burns more cleanly. For example, a study by the Colorado Division of Public Health and the Environment (DPHE) study showed E10 reduced hydrocarbon pollution like benzene by 16.5%.
- Ethanol uses less energy. The most reliable third party studies show that ethanol clearly has a positive energy balance. For one, NRCan says that corn ethanol has an energy

balance that is roughly 40% superior to that of traditional fossil fuels. That rises to as much as 90% when we move from corn to cellulosic ethanol.

- Ethanol cuts smog. Studies show that ethanol reduces particulate matter by up to 50%, reduces tailpipe emissions by as much as 30% and reduces toxic emissions by 30%.
- No harm to water. A study conducted for the Governors' Ethanol Coalition, "The Fate and Transport of Ethanol-Blended Gasoline in the Environment," concluded that ethanol poses no threat to surface water and ground water.

Full fuel cycle greenhouse gas (GHG) emissions and criteria air contaminants (CAC) tail pipe emissions are the main studied issues on the impacts of fuel ethanol on the environment.

Canadian fuel ethanol production and use is expected to reduce GHG emissions by displacing gasoline (on a volumetric basis). Calculated on a full fuel cycle basis, these reductions achieve 30 - 40% per litre for grain-based ethanol (3-4% for E-10) and 60 - 80% per litre for cellulosebased ethanol (6-8% for E-10) (Natural Resources Canada 2003). Because lignin and not fossil fuel is used to drive the production process, the cellulose-based EcoEthanol produced by Iogen Corporation diminishes GHG emissions by 90% (Iogen Corporation 2004).

Concerning CAC emissions2 , ethanol blended with gasoline diminishes carbon monoxide (CO), hydrocarbons (VOCs), particulates (PM) and sulphur (SOx) and it increases nitrogen oxides (NOx) and aldehyde (VOC) (Cheminfo Services Inc. et al. 2000). Aldehyde emissions are mostly handled by vehicle catalytic converters (Government of Manitoba 2002b). The United States Environmental Protection Agency complex model estimates that total tailpipe emissions are reduced by 4,08% when using E10 rather then pure gasoline (Manness, Nicholson and Nicolaou 2002).

Other environmental impacts to be considered are CAC emissions from ethanol plants and the environmental impact of agriculture. Some U.S. reports signalled that emissions from existing U.S. ethanol plants were exceeding U.S. EPA recommended levels. New emission control technologies, which dramatically reduce plant emissions, are currently being fitted in new and existing U.S. facilities (Manness et al. 2002).

Concerning the environmental impacts of agriculture, Pimentel (1991) contends that U.S. corn production is a non-renewable resource and consequently so is the corn ethanol production. His main arguments are: i) soil erosion (18 times faster than speed at which soil can be reformed) and ii) groundwater depletion (25% faster than the recharge rate). Another environmental impact of agriculture to consider but not analyzed in the literature revised for this paper is the environmental risk associated with genetically modified plants being developed for ethanol production.

Ethanol produces a decidedly positive energy balance.

- Studies show an ethanol advantage. NRCan says that corn ethanol has an energy balance that is roughly 40% superior to that of traditional fossil fuels. That rises to as much as 90% when we move from corn to cellulosic ethanol.
- New plants are far more efficient. Newly-built refineries are modernized and energy efficient practices are the standard now. Every ethanol refinery in Canada relies on natural gas and has a positive energy balance.

- Use a lifecycle analysis. It's important to examine energy balance based on the entire lifecycle – that is to say all the inputs and outputs involved. NRCan's GHGenius model calculates the energy required to produce renewable fuels. Since GHGenius is a lifecycle model, it takes into account the energy imbedded in the coproducts from the production process and adjusts. The energy balances for renewable fuels production in Canada are all positive.
- Rising oil prices generate environmental risks. As prices soared well above $100 per barrel in 2008, oil companies began exploring new sources of production that are more remote and require energy intensive extraction methods. This included deep sea drilling of the kind that has caused such controversy in the Gulf of Mexico (and subsequently a catastrophic oil spill in 2010 when PB's Deepwater Horizon rig exploded) – as well as the tar sands and arctic exploration. These all carry increased environmental risks, require the expenditure of even greater rates of energy, and contribute much more to greenhouse gas emissions. It is these additional sources of petroleum fuel, which will be displaced by renewable fuels such as ethanol.
- Sustainability of Grain-Based Ethanol

There is more than ample supply to meet the demand that ethanol production generates – and meeting that supply will get easier, not harder in the years to come.

- A grain surplus. Canada typically produces just less than 50 million tonnes of grain (wheat, barley, corn, oats, rye) annually, and exports about half of it. Consider: if all Canadian gasoline contained 10% ethanol, about 8 to 9 million tonnes of grain would be required. Even at this level, Canada would remain a major grain exporter.
- The truth about demand. Only about 5.7% of global grain production (3.7% after netting out byproducts) and 10% of global vegetable oil production is now used to make 85 billion and 15 billion litres of ethanol and biodiesel, respectively. The respective US numbers are 54 and 1.5 billion.

Growing more grain per acre. Advancements in plant biotechnology have allowed Canadian farmers to grow more corn per arable acre with a softer environmental footprint. The promise of drought-tolerant crops in the next five years will help farmers cope with climate variability. Additionally, ethanol produced from corn only uses the starch from the grain, the remaining protein, fat and minerals is used in animal feed. FACT: Biotechnology has increased crop yields significantly. Since new varieties were introduced in 1996, Canadian corn yields, for example, have increased 33%from 112.4 bushels per acre to 156 bushels per acre in 2008.

- FACT: Seed companies like Monsanto want to keep improving yields for all their crops. Specifically, they are working to double yields in our core crops of corn, soybeans, cotton and spring-planted canola by 2030, compared to a base year of 2000. These yield gains will come from a combination of advanced plant breeding, biotechnology and improved farm-management practices.

Feedstock diversity is the way of the future. Increasingly, components such as non-recyclable municipal landfill waste, low-input dedicated energy crops on marginal land such as growing switchgrass and camelina, forestry and wood waste, and other forms of waste biomass will form an increasing percentage of our renewable fuel feed stocks.

- FACT: Researchers are developing biocatalysts – enzymes, yeasts and bacteria that are used to convert any organic matter into cellulosic ethanol – an attractive option since feed stocks such as agricultural by-products, grasses and wood chips are cheap and abundant. Converting these feed stocks into ethanol requires less fossil fuel in the production process and uses the whole plant, rather than just the grain.

4.6.3. Production process

Starchy materials are converted to ethanol by two major processes, dry milling and wet milling.

Dry milling

Dry milling is the dominant and more efficient ethanol production process than wet milling. It produces about 2.8 gallons of ethanol per bushel of corn (Rendleman and Shapouri, 2007). The schematic of dry milling is shown below（Figure 38）

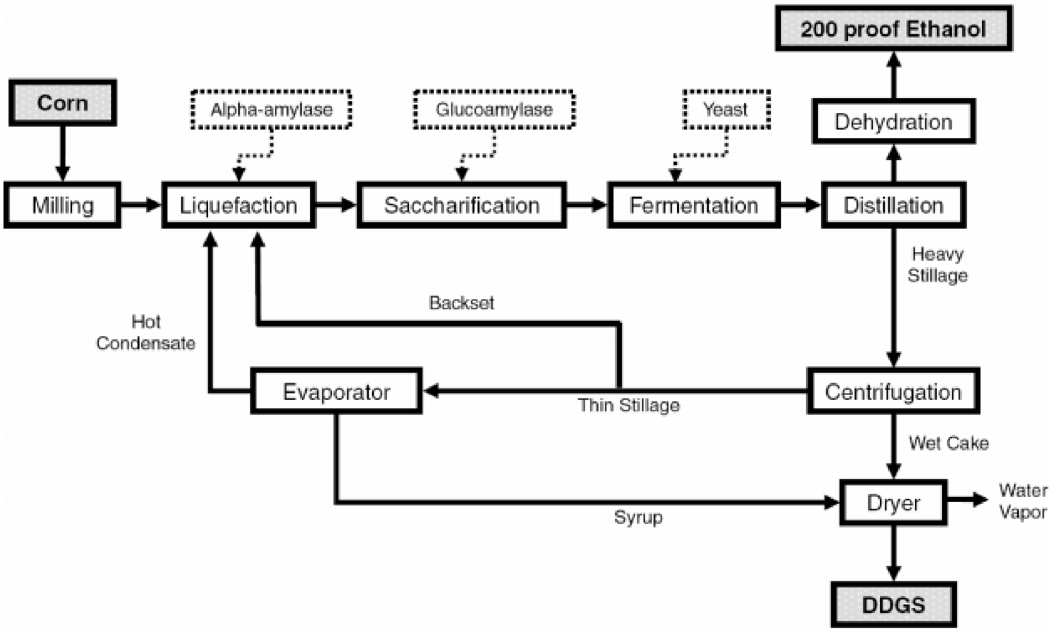


Figure 38. Schematic of dry milling ethanol production

Wet milling

The components of grain are separated in wet milling before saccharification. Produces various high value products such as corn gluten meal (CGM) and corn gluten feed (CGF) are produced though wet milling. It produces about 2.7 gallons of ethanol per bushel of corn (Rendleman and Shapouri, 2007). The schematic of wet milling is shown below (Figure 39).

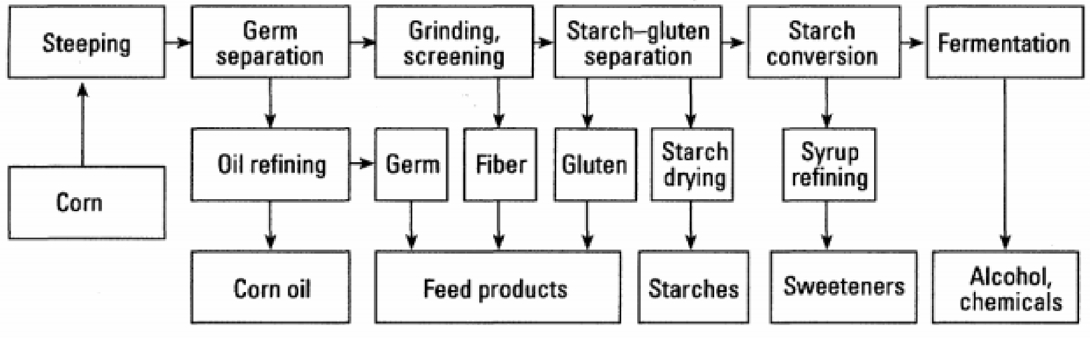


Figure 39. Schematic of wet milling ethanol production

4.6.4. Ethanol purification

Fermentation by-products

Ethanol is produced by yeast fermentation. Although yeast mainly produces ethanol, it also produces by-products. These by-products need to be removed to obtain pure ethanol. There are mainly two kinds of by-product sources, starch and lignin. Starch derived by-products include esters, organic acids, and higher alcohols. Lignin derived by-products include cyclic and heterocyclic compounds.

Purification techniques

Fermentation by-products are mostly removed by distillation. However, volatile by-products tend to lodge more in ethanol. Also, especially for drinking or pharmaceutical purpose, high concentration of ethanol is not required. In this case, further distillation is just waste of energy and money. Many studies have done to find a new purification technique of ethanol which can take place of distillation.

Distillation is the most dominant and recognized industrial purification technique of ethanol. It utilizes the differences of volatilities of components in a mixture. The basic principle is that by heating a mixture, low boiling point components are concentrated in the vapor phase. By condensing this vapor, more concentrated less volatile compounds is obtained in liquid phase. Distillation is one of the most efficient separation techniques. However, it contains several problems. One is separation of volatile compounds. In ethanol production, a distillation tower is designed to separate water and ethanol effectively. Water is obtained from the bottom of the tower and ethanol is obtained from the top of the tower. It is expected that impurities with similar boiling points to ethanol lodges in ethanol even after distillation. Second is its cost. Distillation is a repetition of vaporization and condensation. Therefore, it costs a lot.

Adsorption is a separation technique utilizing a large surface area of adsorbent. Compounds are simply adsorbed on the adsorbent depending on their physical and chemical properties. In general, bigger particles tend to be adsorbed more due to their low diffusivities. Also, compounds with the similar polarity to the adsorbent surface tend to be adsorbed more. When purification of ethanol is considered, non-polar surface and wide ranging pore distribution are favorable since ethanol is polar compounds and various sizes of particles could be contained in ethanol as impurities. From water treatment, activated carbon (Demirbas et al., 2008) and activated alumina (Tripathy and Raichur, 2008) are the most expectable adsorbents.

Ozone is a tri-atomic molecule consisted by three oxygen atoms. Ozone could decompose various kinds of compounds using its strong oxidation potential. Decomposition of compounds could result in changes in physical and chemical properties of compounds such as increases in volatility, biodegradability, and a decrease in toxicity. Although oxidation of ethanol could be expected with oxidation, it does not happen under the atmospheric condition (Bailey, 1982). Thus, ozone can remove impurities without a significant damage on ethanol. There are still some problems, non-oxidizable compounds and ozonolysis by-products. It is expected that 6 some compounds cannot be oxidized by ozone. These compounds will remain after ozonation. Also, ozonation is an oxidation process and not remove compounds physically. Thus, ozonation could generate new compounds, ozonolysis by-products. These compounds should be removed after ozonation by post-ozonation treatments.

4.6.5. Technical Improvement

The Siftek^{TM} Membrane for Ethanol Dewatering

After corn, steam is the most important cost in the production of ethanol Steam represents approximately 15% of the total. ethanol production cost estimated at $1.61/gal(Peschel et al, 2006). Distillation/dehydration consume 40% of the well-to-wheel fossil-fuel energy required for the whole bio-ethanol process (Kim and Dale 2005)

Replacement of distillation/dehydration by vapor separation with the SiftekTM membrane can save up to 50% of the distillation / dehydration energy

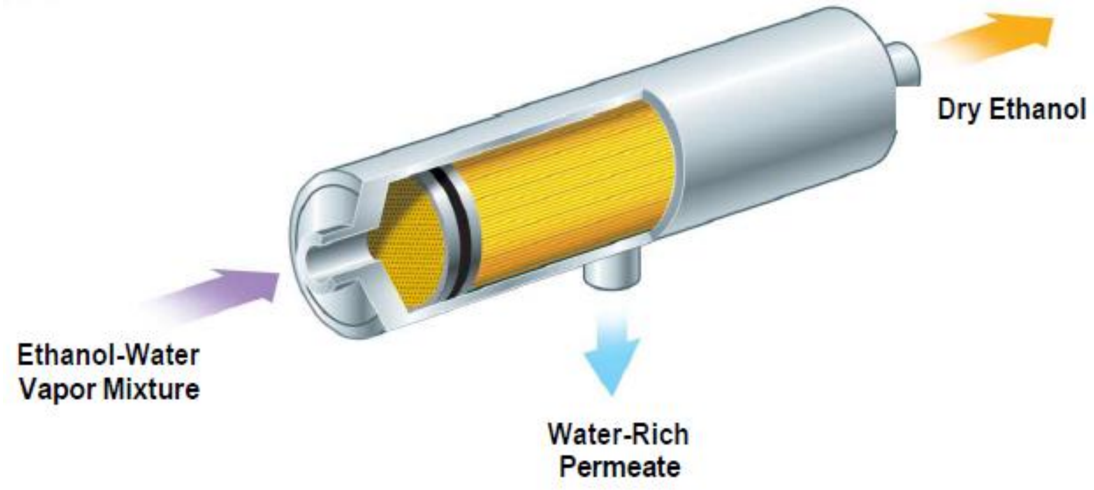


Figure 40. Siftek^{TM} membrane

Features

- Hollow fibre cartridge into a stainless steel pressure vessel
- Vapor feed at 212-220°F at a pressure of 6-7 psi gage
- Water removed under vacuum in a continuous process

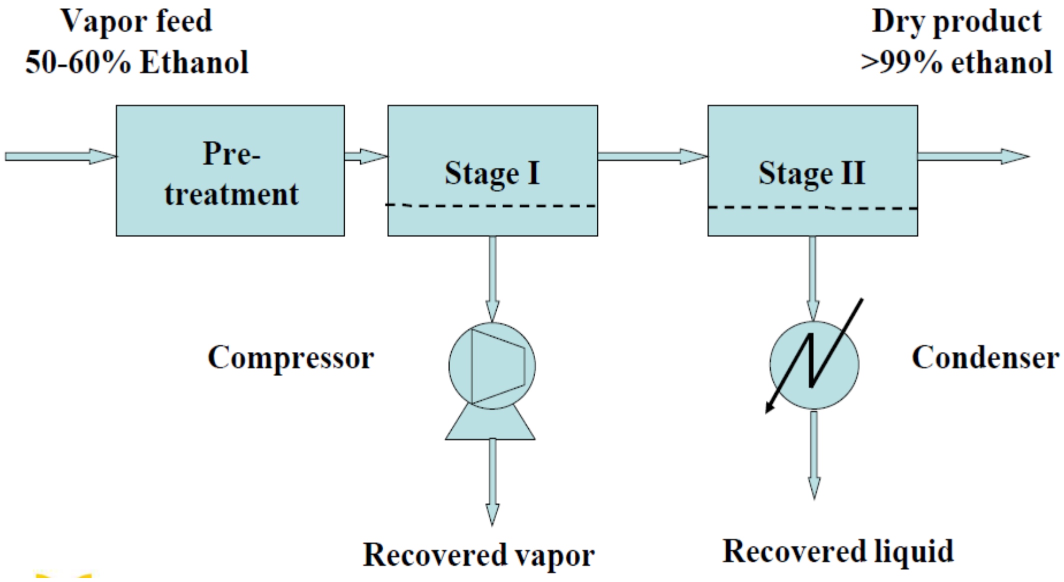


Figure 41. Components of a Siftek^{TM} system

Stage I

- Vacuum of minus 10-12 psi gage
- Mechanical vapor recompresion
- Vapor is essentially pure water
- Can be reused as heating steam

Stage II

- Vacuum of minus 13-14 psi gage
- Condensation + vacuum pump
- Small concentration of ethanol in water
- Stream recycled to fermenter or beer column feed

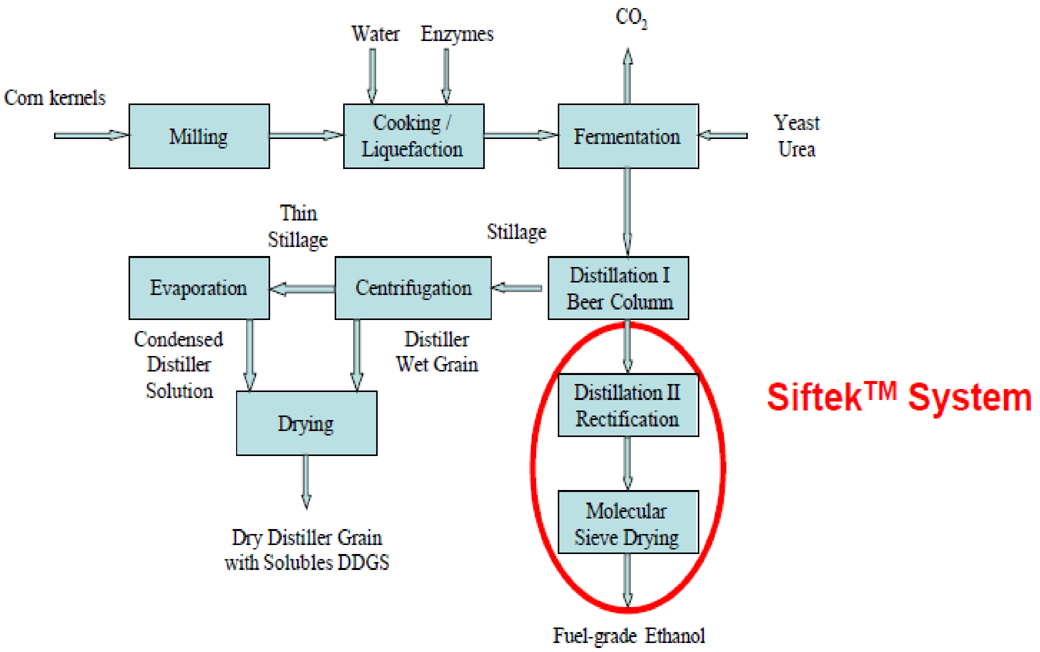
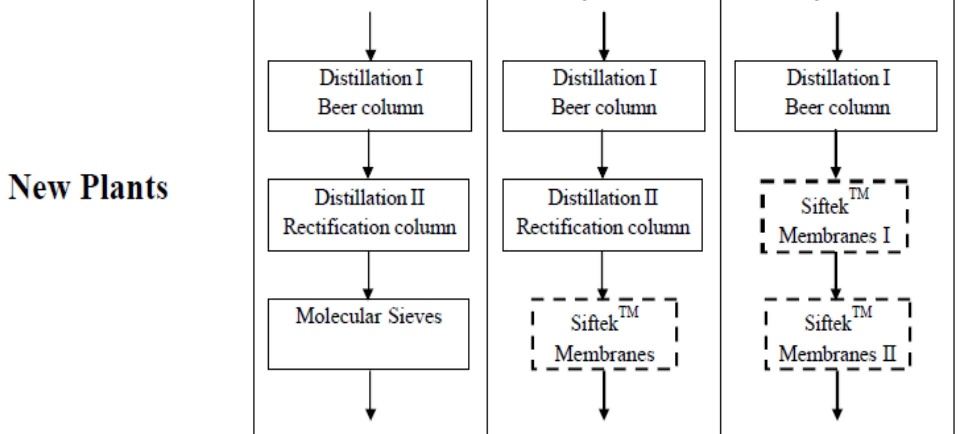


Figure 42. Conceptual process flow diagram for a Dry-milling ethanol plant

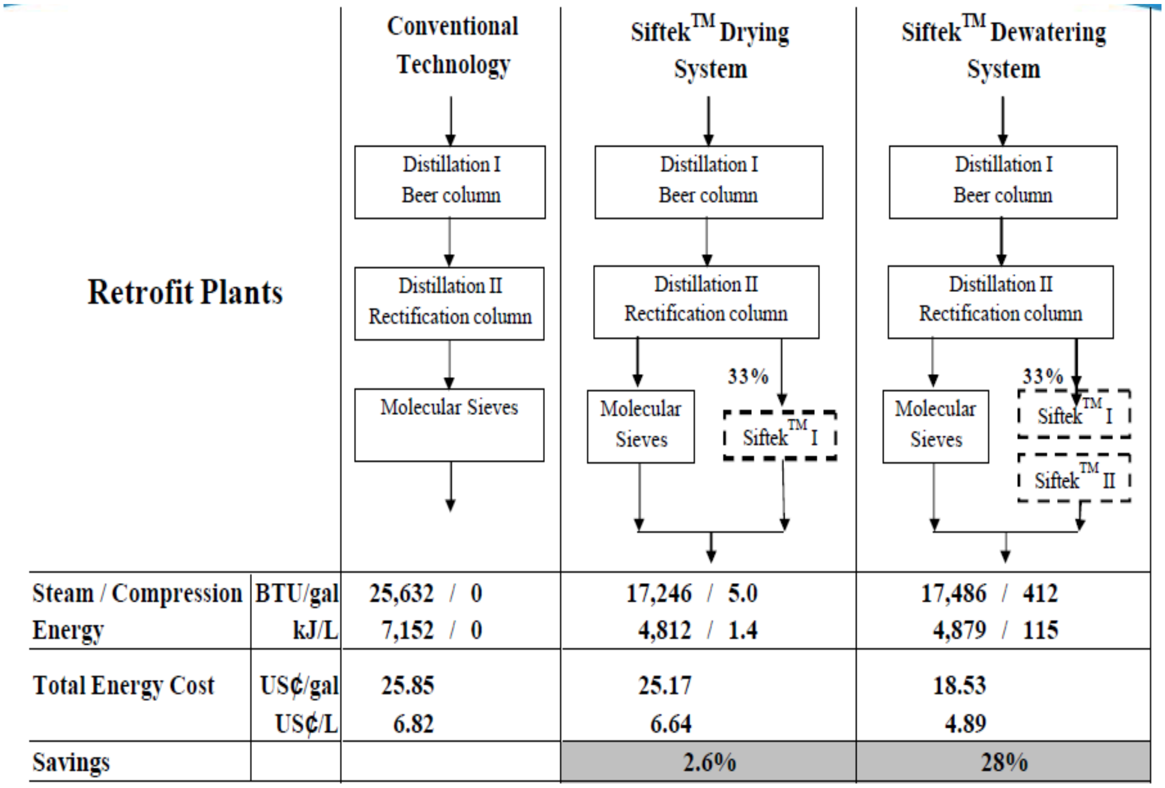
Energy Comparison

Table 67. Energy comparison for new plants



		Conventional Technology	Siftek^{TM} Drying System	Siftek^{TM} Dewatering System
Steam / Compression Energy	BTU/gal kJ/L	17,942 / 0 5,006 / 0	17,248 / 14.8 4,812 / 4.1	7,923 / 1652 2,211 / 461
Total Energy Cost	US¢/gal US¢/L	16.13 4.26	15.52 4.10	9.16 2.42
Savings			3.8%	43%

Table 68. Energy comparison for retrofit plants



Retrofit Plants		Conventional Technology	Siftek^{TM} Drying System	Siftek^{TM} Dewatering System
Steam / Compression Energy	BTU/gal	25,632 / 0	17,246 / 5.0	17,486 / 412
	kJ/L	7,152 / 0	4,812 / 1.4	4,879 / 115
Total Energy Cost	US¢/gal	25.85	25.17	18.53
	US¢/L	6.82	6.64	4.89
Savings			2.6%	28%

4.6.6. Conclusions

The Terra Grain Fuels in a large part of the energy consumption is in the process of ethanol distillation dehydration, if a good solution to the energy consumption in this process can reduce carbon dioxide emissions to some extent. As mentioned above, the energy saving rate of Siftek^{TM} Membrane technology in dehydration and distillation is 30-50%. For The Terra Grain Fuels, the total Emissions for 2013,2014,2015 are 75,092 67,141, and 73,879 tonne respectively If Siftek^{TM} Membrane technology is used, it will reduce emissions 22,527 20,142 22,163 tonne respectively.

- Ethanol producers cannot control the cost of raw materials, but they can reduce processing costs with innovative technologies
- After corn, the largest production cost is energy and the largest amount of energy is for distillation
- A polymeric membrane that can dry ethanol in the vapor phase was introduced
- Energy reductions are obtained because the membrane can remove large amounts of water in a continuous process and without phase change
- The membrane can be used for new plants or retrofits
- In a new plant, the technology can reduce energy by 43% as compared to currently best available distillation technology – equivalent to 7.0 ¢/gal
- In a retrofit plant, the technology can de-bottleneck the plant and reduce energy
- The pay-back is less than 1 year for new plants and 1-2 years for retrofits

And because the process is energy efficient, it consumes less fossil fuel, produces less GHG, and has a low carbon footprint. It has no liquid waste stream and water can be recycled to the front end of the plant. It entails smooth, continuous feed treatment; furthermore, it is easy to add more modules in parallel to enhance capacity. In sum it features greater flexibility and easier scale up.

Many of the features can be related back to the properties of the membrane material itself- i.e. polyimides- that is chemically stable and provides high temperature resistance. It can withstand a wide range of process conditions in terms of water content, temperature and pressure of feedstock. Finally, as a result of all the above, the process is capital cost competitive and entails low maintenance costs.

4.7. Real reduction ability analysis of Manufacturing-pulp

Table 69. Real reduction ability analysis of Manufacturing-pulp industry

Production link	**Technology**	**Rate of mitigation**
Disposal of scrap wood	Pyrolysis (The technology is not yet mature)	Not available
Treatment of waste liquid in pulp-making	The developed hybrid treatment process	34%-51%
All links	Heat and power cogeneration for some enterprises	To be evaluated

The pulp and paper (P&P) industry is very energy intensive. Major advances have been made in the last two decades towards lower energy costs in the Canadian (P&P) industry. However, enhanced energy-efficiency measures implemented in (P&P) mills have been mostly limited to low-investment, high-return projects, except for the revamping and upgrading of boilers. Advanced engineering techniques, such as pinch analysis, are now routinely used and with success to maximize internal heat recovery. Process integration combining several approaches such as water system closure, production of power by cogeneration and heat-exchange networks optimization has paved the way for new and innovative solutions. It is becoming evident that low-investment measures will not suffice to meet these more ambitious goals. The perspective for future action is changing.

In the production process of the manufacturing-pulp company, the main carbon emission links are the process of waste wood incineration and waste water treatment. The technology of emission reduction can theoretically adopt pyrolysis technology in the disposal of waste wood, but this technology has not been actually utilized, because the capacity of emission reduction is still to be discussed. As for the treatment of waste liquid in pulp-making, we have applied the result of a case study. The results show the advantages of the developed hybrid treatment process compared to the conventional hybrid and aerobic treatment methods. Therefore, the measures to reduce emissions can start from these two points.

In addition, pulping process requires a lot of heat and electricity, and generates a lot of waste liquid and waste. Without recycling, it will cause environmental pollution. During the recovery process of waste liquid and waste, such as in the process of alkali recovery, the recycled alkali can be used in production, and the generated steam can be used for power generation. Therefore, the pulping and papermaking enterprises have both the demand for thermoelectricity and the conditions for the production of heat and power. (The specific content is in the appendix) Many of pulp and paper enterprises used to supply electricity in the past to the public power grid and the independent boiler room, with low energy utilization rate. If combined heat and power is produced, these enterprises can achieve cascade utilization of energy, improve energy efficiency and save energy and reduce pollutant emissions.

4.7.1. Technological process - using evaporators to achieve zero effluent at BCTMP pulp mill

When Millar Western Pulp (Meadow Lake) Ltd. announced plans to build a mill in northern Saskatchewan, the community was concerned about the pollution it would generate, especially effluent discharged to the Beaver River. Though a biological treatment system planned at the mill would have made the effluent cleaner than river water, Millar Western decided to go one step further and eliminate all effluent discharge from the pulp mill. The zero effluent system at Meadow Lake is the first of its kind in the world. It was devised by Millar Western Pulp and NLK Consultants, Inc., the engineers for the project. The evaporator system, the key equipment in the water recovery process, was designed and supplied RCC (now SUEZ).

All effluent coming out of the mill is treated in the water recovery plant. As a result, the mill only needs about 300 gpm (68 m3/h) of makeup water to replace water lost to the atmosphere by evaporation. The same type of pulp mill without a water recovery plant would need about 2500 gpm (568 m3/h) of raw water makeup. Figure 43 shows the BCTMP pulping process and its use of recovered water.

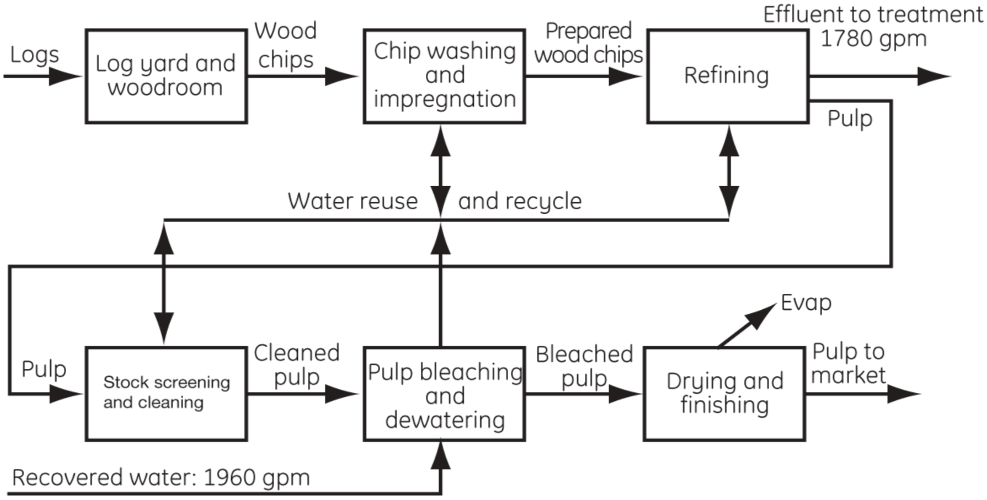


Figure 43. Water use in the BCTMP pulping process

The zero effluent water recovery system

The effluent produced by the BCTMP process is discharged at a rate of about 1800 gpm (410 m3/h). It has a temperature of 150 °F (66°C), a pH of about 8 and contains about 20,000 ppm (mg/L) dissolved solids. Figure 44 shows the overall water treatment process including softening of the raw water makeup. Figure 45 shows a more detailed view of the water recovery portion of the system, consisting of five stages: clarification, evaporation, concentration, stripping and incineration.

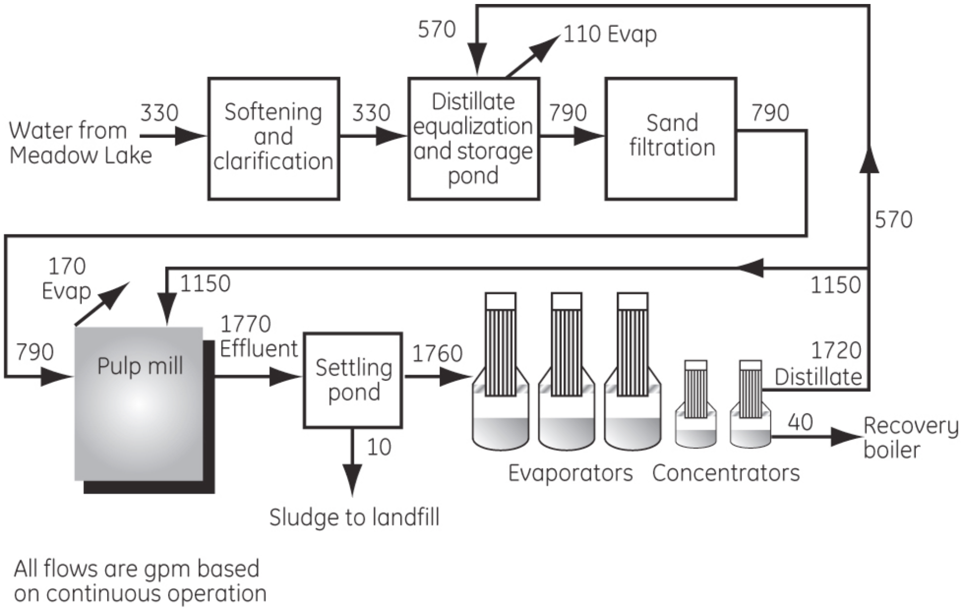


Figure 44. Millar Western water recovery process overview

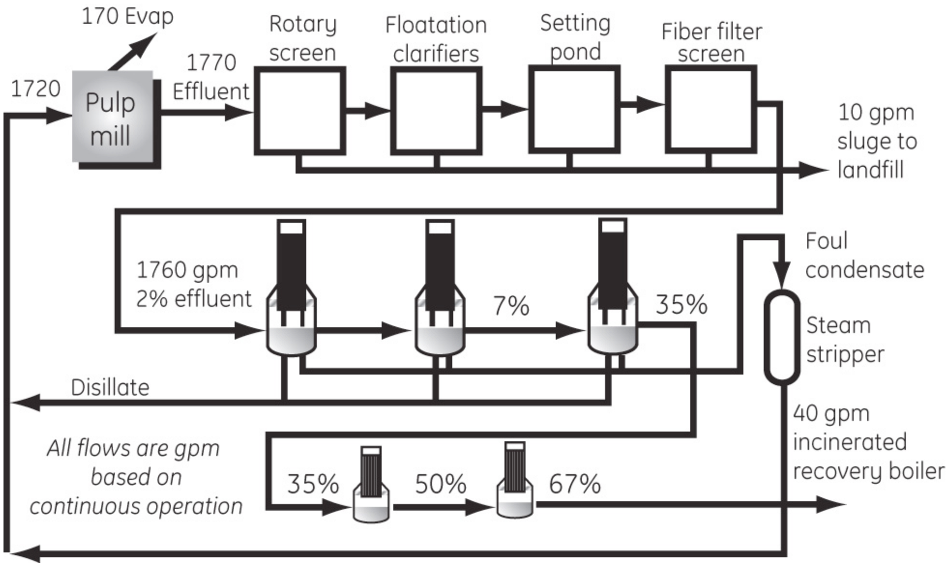


Figure 45. Millar Western effluent treatment system

Clarification

The first unit operation to receive pulp mill wastewater is the floatation clarifiers. Since removal of fiber is very important to the performance of the evaporators, the mill decided to install two clarifiers instead of one. This allows for maximum removal efficiency and flexibility. Chemicals are added to aid in flocculation and floatation of the solids. To ensure that upsets in the pulp mill do not directly affect the evaporators, an on-line meter measures suspended solids in the clarifier accepts stream. When the suspended solids 900 ppm (mg/L), the clarifier accepts are directed to the settling ponds. Clarifier accepts normally go directly to the evaporators in the winter to conserve heat. In the summer the accepts go preferentially to the settling pond to dump heat since the heat balance changes from season to season.

Evaporation

The heart of the zero effluent system is three vertical-tube, falling-film vapor compression evaporators. At 100 feet (30 m) tall, and with thousands of square feet of heat transfer surface, this is the largest train of mechanical vapor recompression evaporators in the world. The evaporators concentrate effluent from 2% solids to 35%, using an energy-efficient mechanical vapor compression process to recover distilled water from the effluent. The evaporator consists principally of a heating element, vapor body, recirculation pump, and a vapor compressor. (Figure 46).

The effluent is pumped from the vapor body sump to the top of the heating element (tube bundle). A distributor is installed in the top of each tube, causing the effluent to flow down the inside of each tube in a thin film. The distributor helps prevent fouling of the heat transfer tubes by keeping them evenly and constantly wet. It also allows the mill to operate at reduced capacity if desired, since the heating surfaces will remain wet regardless of the amount of effluent being processed. (The evaporators are also capable of handling 1.2 times more than design flow rates from the pulp mill which gives the mill a significant amount of catch-up ability). When the effluent reaches the bottom of the tubes, the recirculation pump sends it back to the top for further evaporation.

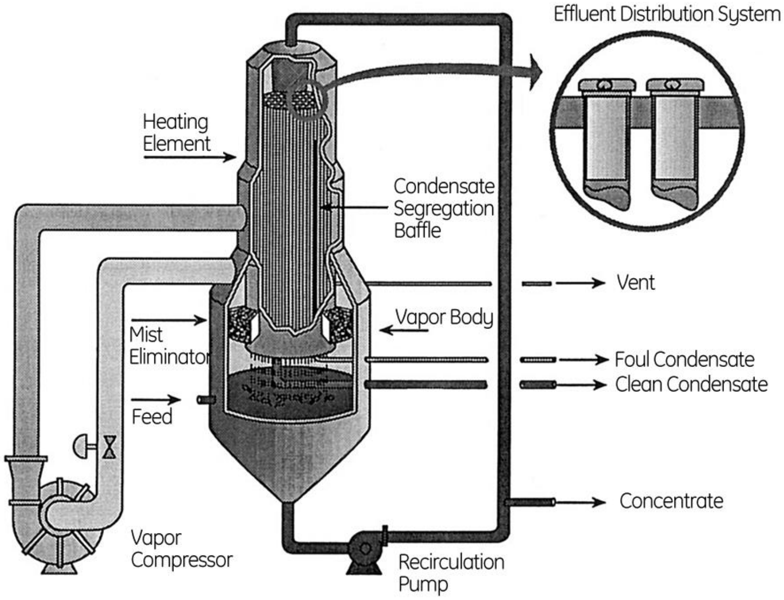


Figure 46. Evaporator

As the effluent flows through the heated tubes, a small portion evaporates. The vapor flows down with the liquid. When it reaches the bottom of the tube bundle, the vapor flows out of the vapor body through a mist eliminator and then to the compressor, which compresses it a few psi. The compressed steam is then ducted to the shell side of the tube bundle, where it condenses on the outside of the tubes. As it does so, it gives up heat to the tubes, resulting in further evaporation of the liquid inside. A large amount of heat transfer surface is provided, which minimizes the amount of energy consumed in the evaporation process. Operation of the vapor compression evaporator system requires only 65 kWh per 1000 gallons (3.8 m^3/h) of feed.

As the vapor loses heat to the tubes, it condenses into distilled water, which flows down the outside of the tubes. Because the water that first condenses out of the steam is cleaner than water condensing later, baffles are provided within the heating element to create two separate regions for condensing. Steam flows first through the clean condensate region where most condenses. The remaining vapor, which is rich in volatile organics such as methanol, condenses in the foul condensate region of the heating element.

A major portion (70%) of the clean condensate is sent directly to the pulp mill for use as hot wash water at the back end of the mill. The balance of the clean condensate goes to the distillate equalization pond where it is combined with makeup water from Meadow Lake and serves as the cold water supply to the mill. The foul condensate, which contains the volatile organic materials, is reused after stripping in a steam stripper. Virtually nothing more than a minor vibration problem in the evaporator electrical motors was encountered during the startup, allowing continuous operation with no unscheduled down time to affect pulp mill production.

Concentration

Like the three evaporators, the two concentrators are vertical-tube, falling-film design. Rather than using a vapor compressor to drive the system, the concentrator is operated with steam generated by the recovery boiler.

The evaporation process in the concentrators is essentially the same as in the evaporators, but the effluent is concentrated further, to about 67% solids. The concentrated effluent is incinerated in the recovery boiler. The lead concentrator takes the liquor from 35% to 50%, while the lag concentrator goes from 50% to 67% solids.

During startup, there was some concern that the final liquor might be too thick to pump. As it turned out, the liquor was easy to handle at operating temperatures. After eight months of operation, no serious plugging has occurred in the concentrators and scaling has been minimal. Each concentrator can be switched to water wash mode while liquor storage tanks are drawn down, then placed back in service with no shutdowns upstream at the evaporators or downstream at the recovery boiler.

Stripping the foul condensate, only about 10% of the total condensate, is stripped of volatile organics in a packed column stripper. Volatile organics are selectively concentrated in the foul condensate because of the condensate segregation features built into the evaporator heating elements. Process steam from the concentrator is sent to a reboiler, which generates stripping steam from a portion of the stripped condensate. The stripped condensate is combined with the clean condensate and reused in the mill. The stripped volatile organics are incinerated in the recovery boiler as a concentrated vapor.

Incineration

At the recovery boiler, the organic components of the effluent are incinerated, a process that also generates steam to operate the concentrators. Inorganic chemicals in the effluent are recovered in the smelt from the boiler, which is cast into ingots and stored on site. The mill is considering recovering the sodium carbonate, which would then be converted to sodium hydroxide, a major chemical used in the BCTMP process.

Water storage

In the mill there are many tanks and chests for storing white water, pressate and wastewaters. Likewise, in the water recovery plant there are storage chests for mill water and various concentrations of liquor. But the heart of the water storage system lies in five major ponds holding 48 million gallons (Figure 47). The ponds are split into two settling ponds and one water recovery pond holding all wastewater volumes. The two settling ponds hold 1.3 million gallons (4900 m^3) each and are concrete-lined to facilitate dredging when required. The water recovery pond holds 6.3 million gallons (24,000 m^3) of wastewater and is concrete-lined along the sides to prevent erosion and clay-lined on the bottom.

The distillate equalization pond and water storage reservoir hold all the clean water. The distillate equalization pond is a bio-polishing pond where the small amount of volatile organics that come over with the distillate are consumed by biological action. This pond holds 8.4 million gallons (32,000 m^3) while the water storage reservoir holds 29 million gallons (110,000 m^3). Both ponds have a 60 mil poly liner.

Having the large storage basins for wastewater give the pulp mill two days of run time with the water plant completely shut down. If makeup water from the lake is down, the pulp mill can run for 20 days from clean water inventory in the water storage reservoir. Also, if there is a recovery boiler outage, the pulp mill and evaporators can continue to run for 30 days without being affected.

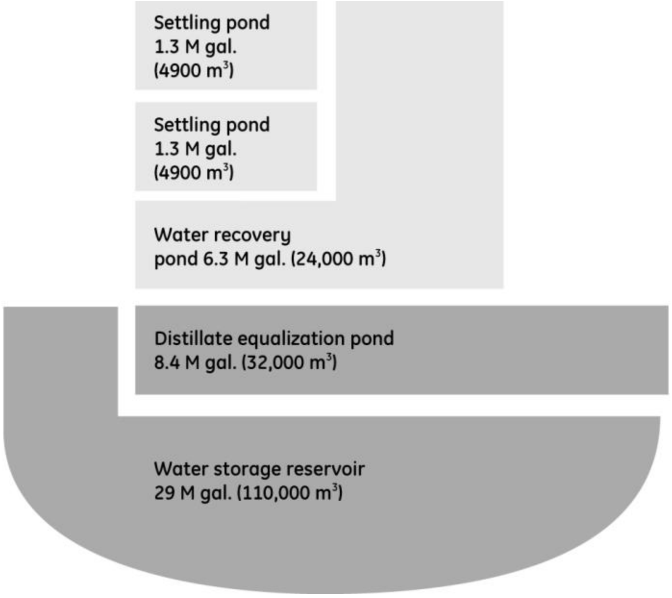


Figure 47. Millar Western water ponds

Without the pond system, the operation of the pulp mill would be totally dependent on the operation of the water recovery plant. An evaporator trip or recovery boiler outage would directly cause lost production in the pulp mill. Because the design is so flexible, an evaporator trip has no effect whatsoever on pulp mill production. An emergency shutdown in the pulp mill allows for slow turndowns in the water plant.

Conclusion

Perhaps the best way to describe the success of the water recovery plant is that the pulp mill operators barely recognize that they are in a zero effluent environment. They have access to all the water they require and it is better quality than lake or river water. The water recovery plant has not caused any lost production in the pulp mill other than for normal maintenance of the equipment. No off-grade pulp has been produced as a result of water quality.

Washing efficiencies have been excellent and the cleanliness of the pulp, not only in terms of debris, but also organic loading, has been better than expected. In short, the zero effluent mill has proved to be a success.

4.7.2. Major carbon emissions

Figure 48 shows the whole process of making BCTMP in Meadow Lake Mechanical Pulp Inc. Among them, the major carbon emissions have been marked with red outline.

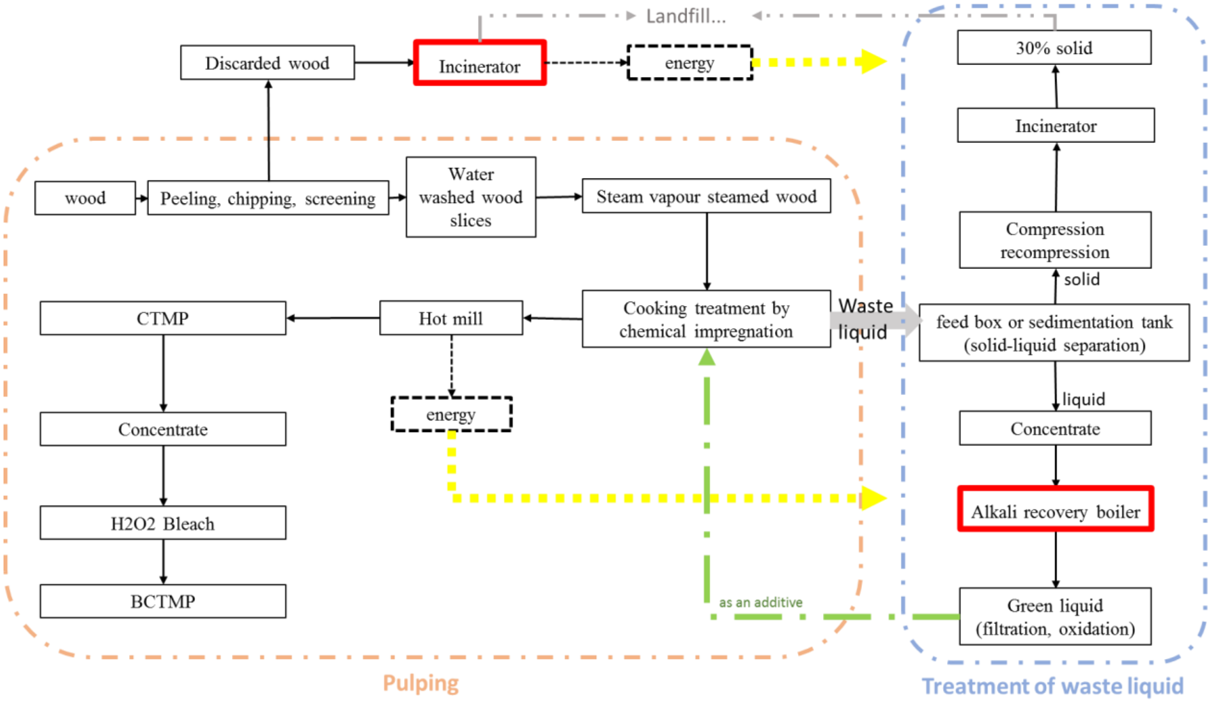


Figure 48. The whole process of making BCTMP in Meadow Lake Mechanical Pulp Inc.

In pulping link, the process of mechanical grinding does not produce carbon emissions, but energy consumption (electricity) is large, and a large amount of carbon is emitted from energy consumption. In waste wood processing link, incinerator combustion, producing carbon emissions. waste liquid treatment link: incinerator incineration of sludge to produce carbon emissions. From the whole process of sludge treatment to sludge carbon emissions disposal results showed that sludge dewatering (water content 5%) after the production process of cement clinker, carbon emissions is negative; and sludge dewatering (water content 75%) carbon emissions after the incineration process is far lower than that of dehydrated lime drying (70% moisture content) after the process of landfill land use etc.. Therefore, from the objective evaluation of the life cycle of carbon elements, it can be said that sludge incineration cannot be identified as a high carbon emission process. In addition, alkali recovery furnace burning a concentrated liquid to produce carbon emissions.

4.7.3. Technical improvement

The atmospheric concentration of carbon dioxide which constitutes the major greenhouse gas (GHG) has increased significantly after the industrial revolution. Many attempts have been made aiming at the reduction of CO_2 in the atmosphere. In order to reduce the carbon emissions of the company, according to many previous research and literature, a case study is presented below, and a feasible way of technological upgrading is put forward.

Case study

In the case study, a hybrid treatment process is developed for CO_2 removal from wastewaters generated by industrial operations. In the developed process, a CO_2-saturated wastewater enters an anaerobic reactor where CO_2 is bio-converted to methane, followed by an aerobic reactor for additional treatment of the wastewater. Evaluating the economic feasibility of the developed hybrid treatment process can treat BCTMP wastewater from the pulp and paper industry, making a comparison of this process with the aerobic and conventional hybrid (anaerobic/aerobic) treatment systems.

Cost estimation and GHG analysis is carried out for the conventional hybrid treatment (system A), aerobic treatment (system B), and the developed hybrid treatment (system C) processes. Based on the effect of wastewater saturation with CO_2 on GHG emission and cost, the feasibility of the developed process (system C) will be investigated. The costs and GHG emissions associated with the developed process are assumed to be the sum of costs and GHG emission from the conventional hybrid treatment system (system A) and costs and emission offsets by applying the scrubber.

The following table shows GHG emissions and costs of the three different systems examined in the present work. The anaerobic treatment alone was not considered as a treatment option because pulp and paper wastewater is usually a high strength wastewater and anaerobic treatment alone cannot meet the discharge standards. However, the presence of anaerobic and aerobic reactors in the hybrid treatment process benefits from the specific advantages of anaerobic treatment such as methane generation, lower energy requirements and sludge production.

Table 70. Treatment systems analyzed based on their GHG emissions and cost

Process design	Main treatment	Second treatment	Tertiary treatment	Nitrogen removal	Solid treatment	CO_2 scrubber
System A	Anaerobic	Aerobic	No	No	Landfill	No
System B	Aerobic	No	No	No	Landfill	No
System C	Anaerobic	Aerobic	No	No	Landfill	Yes

The case study in the present work is based on the operation of BCTMP wastewater treatment plant. The case company is a producer of high yield pulp and is located on the south shore of the Saint Lawrence River at the mouth of the Matane River in Quebec. It applies hybrid treatment process (system A) to treat the generated wastewater. The wastewater treatment process consists of a primary clarification process to remove large particles, followed by secondary biological treatment using an anaerobic internal circulator reactor (IC) and an activated sludge reactor. The flow diagram of wastewater treatment plant is shown in Figure 49. The input and output sources of energy are shown in this Figure. The GHG and non-GHG emissions are shown in red and black, respectively. The information of case company is summarized in Table 71.

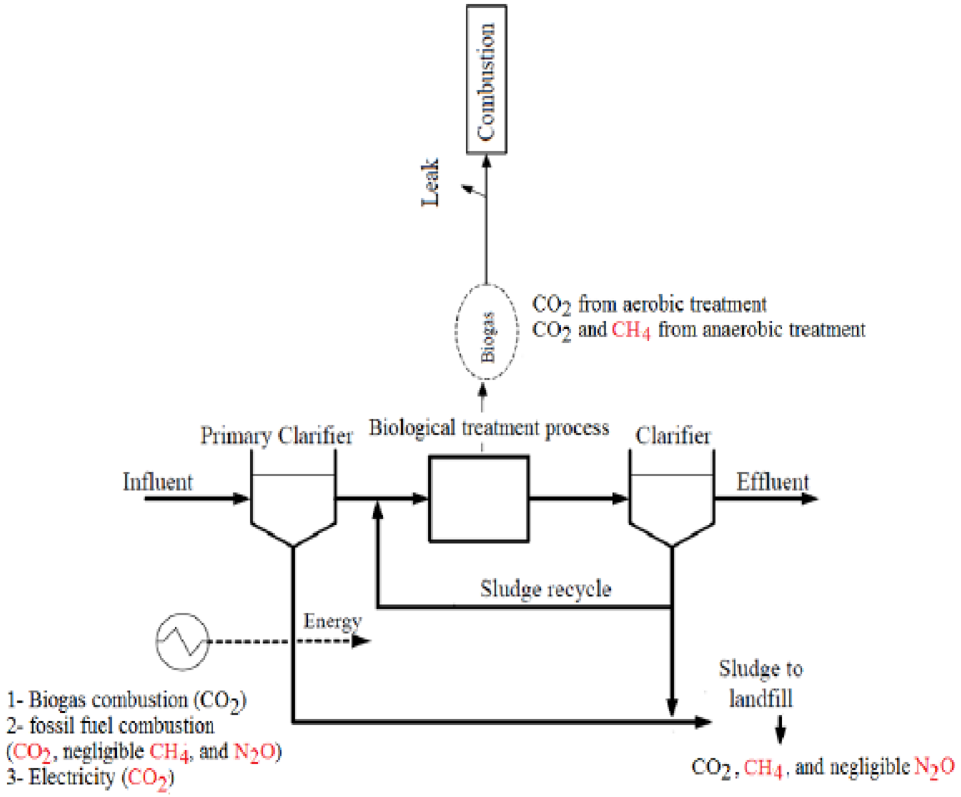


Figure 49. Flow diagram of the examined wastewater treatment system. (GHG emissions are shown in red)

Greenhouse Gas Analysis

The types and magnitude of GHG emissions from case company depend on the applied treatment methods. In the pulp and paper industry, the GHG emissions consist of CO_2, methane and nitrous oxide. Other emissions are negligible. The sources of GHG emissions are classified as on-site and off-site emission sources. The on-site GHG emissions originate due to biological treatment, energy production and sludge treatment. Off-site GHG emissions are related to the production and transmission of fuels and chemicals for on-site use, as well as off-site generation of electricity.

Table 71. Information from the case company

	Anaerobic	Aerobic
Capital cost	25 M (^{1*}2012)	10M (^{2*}1989)= 16.45M(2012)
Solid waste produced	230 m^3/month (sold, 100$/ m^3)	4380 dry ton/y (sent to uncovered landfilled)
Recycling of gas	95% (to dry pulp)	NA
CH_4/kg COD removed	0.4 m^3/kg COD removed	NA
CH4 % in biogas	70-75%	NA
COD removal	65%	85% (80% for system B)
BOD removal	85%	≈100% (95% for system B)
Overall power requirement^{3*}	0.01 kW/m^3 reactor volume	1.5 kWh/ kg COD_{rem}

Other information:
Energy generation for Tembec Matane pulping plant results in 247 million m^3 CO_2/y emission.
Flow, COD and BOD entering the anaerobic digestion are respectively equal to 5 Mm^3/y, 10.2 and 4.8 g/l.

1*Annual index for 2012= 584.6 (Web 2)
2*Annual index for 1989= 355.4, (Brown 2007)
3* Keller and Hartley (2003)

Table 72. Summary of GHG generation and energy consumption for systems A, B, and C

	System A	System B	System C
Energy requirement (M kWh/y)	15.5	60.7	15.7
CO_2 emission from energy generation (tCO_2/y)	14,933	58,265	15,107
CH_4 generation in anaerobic reactor (Mm^3 CH_4/y)	13.2	-	13.4 to 18.7
5% CH_4 leakage from the anaerobic reactor (tCO_2e/y)	9113	-	9,300 to 12,900
95% CH_4 recovery from the anaerobic reactor (tCO_2e/y)	173,150	-	176,740 to 245,000
Energy equivalent of recovered methane combustion (M kWh/y)	115	-	117 to 162
Saving in light oil by combustion of recovered methane (M l oil/y)	11.8	-	12 to 16.7
Revenue of saved light oil by methane recovery (M$/y)	6.5	-	6.6-9.2
CO_2 emission from combustion of the recovered CH_4 (tCO_2/y)	110,000	-	112,680 to 156,000
CO_2 emission from anaerobic reactor (tCO_2/y)	8,680	-	8,680
CH_4 emission from landfilling of aerobic reactor sludge (tCO_2e/y)	4,250	11,359	4,250
CO_2 emission from aerobic reactor (tCO_2/y)	4,400	27,900	4,400
Carbon credit (M$/y)	1.28	0	1.34 to 1.92
Carbon offset (tCO_2e/y)	196,191	0	206,108 to 294,994
Total GHG emission (tCO_2e/y)	13,360	69624	13,550 to 17,150
Total not GHG emissions (tCO_2e/y)	28,010	27,900	28,190

The advantages of scrubber application in the developed hybrid treatment are summarized in the following Table.

Table 73. Advantages of using spray scrubber in system C

Feature	Value
Carbon offset by applying a scrubber (tCO_2/y)	496 to 9,912
Carbon credit for the carbon offset by applying a scrubber ($/y)	3,220 to 64,430
Excess methane generation from anaerobic reactor as a result of applying a scrubber (m^3 CH_4/y)	273,000 to 5,461,000
Increase in methane generation in developed system compared to conventional Hybrid treatment system	From 2 to 41%
Energy equivalent of the excess recycled methane combustion (M kWh/y)	2.4 to 47.5
Savings in light oil fuel consumption by combustion of excess recovered methane from anaerobic reactor (M L oil/y)	0.24 to 4.9

Cost analysis

Cost analysis is carried out to predict if the project is economically feasible for capital investment. The total cost is the summation of capital cost, operational and maintenance costs. The costs for application of the scrubber are estimated based on the EPA fact sheet and the results are summarized in the following Table. The operation costs of the scrubber decrease as the volume of processed gas increases. The maintenance cost, on the other hand, decreases based on the liquid type. If the liquid has very fine particles that do not clog the nozzles, the maintenance costs are much lower. In the case study, the BCTMP wastewater has very fine particles and a large amount of gas passes annually through the scrubber which decreases the operation and maintenance costs. It is not surprising that by applying the scrubber, the maintenance cost is a considerable portion of the costs.

Table 74. Cost of applying a spray scrubber for the case study

Capital cost	$276770 ($10 per scfm)
Operation and maintenance cost	$415155 (22599$ assumed for operational cost, which leaves $392556 for maintenance cost) annually, ($15 per scfm)
Annualized cost	$424381 ($15.33 per scfm)
Life time	30 years (the same as anaerobic treatment life time)

The summary of results of cost estimation for systems A, B and C is presented in Table 72. Table 73 shows that despite the higher capital cost for hybrid treatment systems (system A and C) compared to aerobic treatment process (system B), the total costs would be cheaper. Moreover, a high savings by the combustion of recovered methane instead of fossil fuels is achieved in systems A and C. In system C, the carbon offset by applying a scrubber brings additional revenue compared to system A.

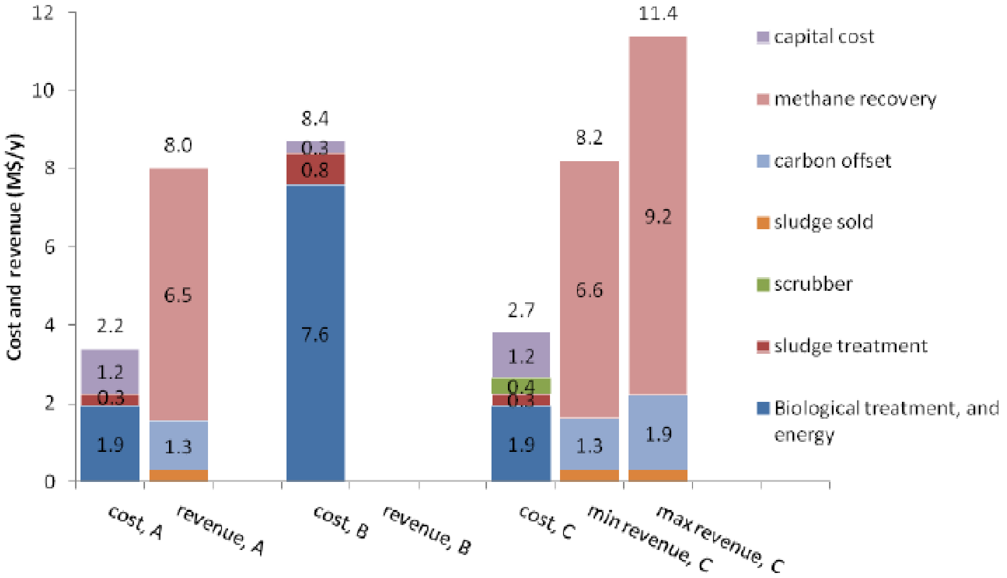
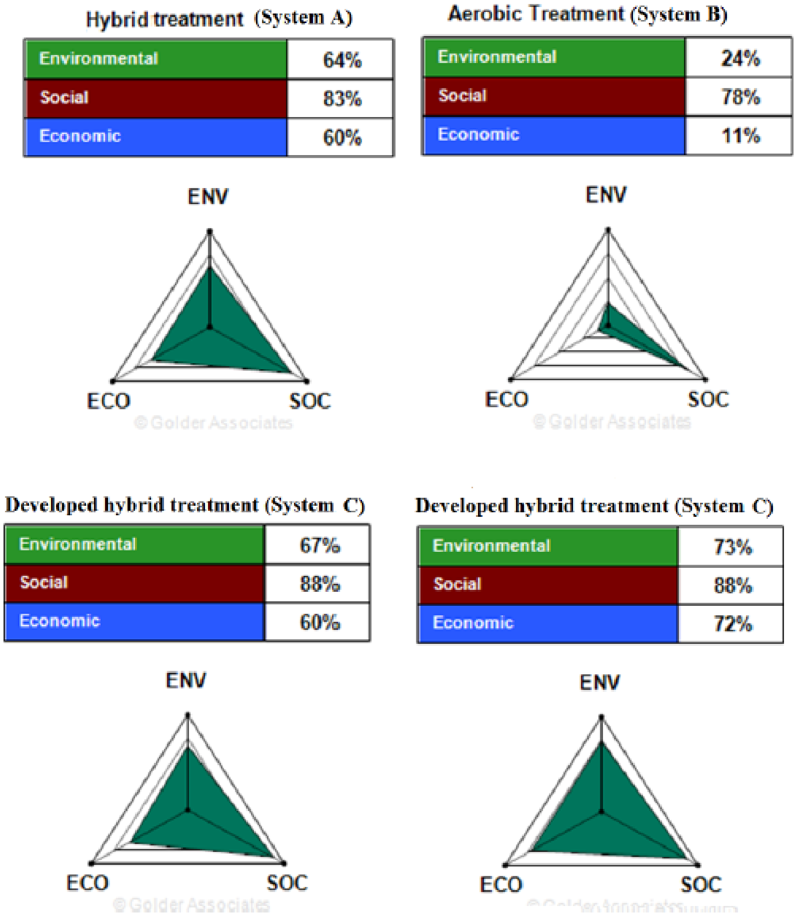


Figure 50. Summary of cost analysis for systems A, B and C

The summary of results obtained from the application of GoldSET software results is presented in Figure 51. In this figure the three systems in the present project are compared based on sustainability features (environmental, social, and economical features). For system C, there is a range of results based on liquid flow rates passing through the scrubber which is equal to 1 to 20 gal/1000 ft3 gas passing through the scrubber. Consequently, the results are shown in two graphs related to the minimum and maximum numbers. Maximum numbers are achieved when higher liquid flow rates pass through the scrubber. From Figure 51, higher values and a higher balance of environmental, social, and economical aspects of sustainability belong to the developed hybrid process (system C), indicating the high sustainability of this treatment method. Also, the results show the advantage of applying hybrid treatment over aerobic treatment for the treatment of BCTMP pulp and paper wastewater.



Hybrid treatment (System A)

Environmental	64%
Social	83%
Economic	60%

Aerobic Treatment (System B)

Environmental	24%
Social	78%
Economic	11%

Developed hybrid treatment (System C)

Environmental	67%
Social	88%
Economic	60%

Developed hybrid treatment (System C)

Environmental	73%
Social	88%
Economic	72%

Figure 51. Summary of the GoldSET software results

Conclusions

GHG emission and overall cost of a developed hybrid wastewater treatment system were compared with those of conventional aerobic and hybrid treatment processes. The developed hybrid wastewater treatment system uses a spray scrubber for the saturation of wastewater with CO_2 before entering the anaerobic reactor. The results showed the advantage of applying hybrid over aerobic treatment.

The addition of CO_2 in the developed hybrid treatment process (compared to conventional hybrid treatment process), increases methane generation by 2 to 41, depending on the volume of wastewater in contact with the gas in the scrubber. The suggested process increases methane generation by 273057 to 5461145 m3 CH4/y compared to conventional hybrid treatment process. The increase in methane generation will in turn increase the potential recovery of methane which will increase energy generation through its combustion, thus producing higher revenue for the plant. Power generation from the combustion of recovered methane in both systems A and C was more than the required power for the treatment process. Besides, CO_2 emission from the combustion of recovered methane for power generation is not considered as a GHG.

The annual cost and revenue of the developed hybrid treatment system was estimated to be 2.7 and 8.2 to 11.4 M$/y, while the corresponding values for the conventional hybrid treatment system was equal to 2.2 and 8M$/y. Aerobic treatment, on the other hand brings no revenue for the treatment plant and has 8.4M$/y cost for the treatment plant. The approximate GHG offset by the developed hybrid treatment, conventional hybrid treatment and aerobic treatment process respectively was equal to 206000 to 295000, 196000 and zero tCO_2e/y. By comparing the conventional hybrid treatment system with the developed hybrid process with respect to GHG emission and cost, it can be concluded that applying a scrubber for the saturation of wastewater with CO_2 is a promising method, especially when higher liquid flow rates can pass through the scrubber. It can annually save up to 3 million dollars in annual costs of treatment plants and will reduce GHG emissions by 100,000 tCO_2e/y. The results confirmed the higher sustainability of the developed hybrid treatment process.

4.8. Real reduction ability analysis of Trans-pipeline

Table 75. Real reduction ability of Trans-pipeline industry

Technical category	Technology	Substance	Rate of mitigation
Reducing Emissions from Compressor Seals	Economic Rod Packing Replacement	methane/ghg	10%-15%
Reducing Emissions from Compressor Seals	Emissions with Dry Seals Replacement	methane/ghg	10%-15%
Adopting technologies that divert or capture the release of methane during maintenance	Portable gas detectors and ultrasonic detectors	methane/ghg	To be evaluated
Adopting technologies that divert or capture the release of methane during maintenance	State-of the-art pipeline simulator	methane/ghg	To be evaluated

The Canadian Energy Pipeline Association (CEPA) represents Canada's transmission pipeline companies who operate approximately 117,000 kilometres of pipeline in Canada. These energy highways move approximately 1.2 billion barrels of liquid petroleum products and 5.3 trillion cubic feet of natural gas each year. Their members transport 97 per cent of Canada's natural gas and onshore crude oil production from producing regions to markets throughout North America.

4.8.1. Improve pipeline safety

The safety of people and the environment is our top priority; take action to reach their goal of zero incidents.

Monitor pipeline corrosion

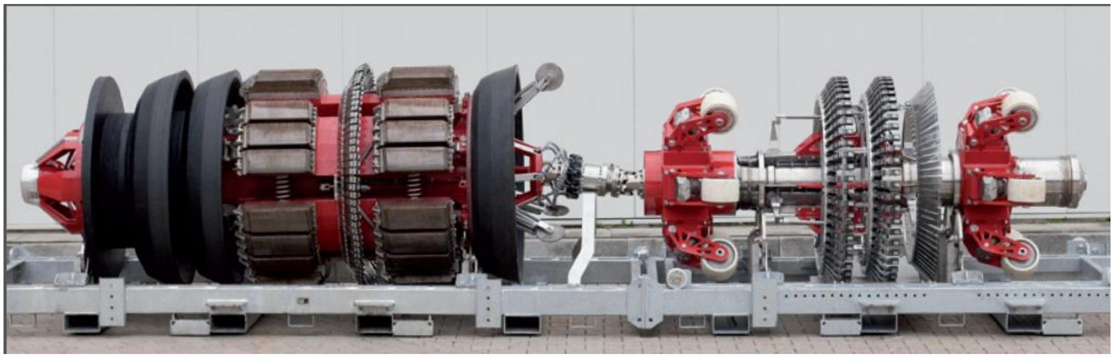


Figure 52. Smart pigs

The transmission pipeline industry continues to improve its processes, techniques and technologies in an effort to monitor pipeline corrosion. For example, technological advances in in-line inspection (ILI) tools called "smart pigs" have substantially increased the industry's ability to detect and identify corrosion issues, which is shown in Figure 52. These highly sophisticated tools travel inside the pipeline and use sensors to identify and locate anything out of the ordinary in the pipe. ILI tools allow operators to collect information regarding the length, width, depth, orientation and location of pipeline flaws. These devices gather valuable information and use advanced software to evaluate the data, helping operators monitor the real-time condition of their pipeline and pinpoint areas that require additional monitoring, maintenance or immediate action to prevent an incident.

In-line inspections

CEPA member companies use data from past in-line inspections, as well as comprehensive engineering and risk assessments of their pipelines, to determine which pipelines to inspect and when to inspect them. The frequency of in-line inspections varies from line to line, but typically they are carried out every two to 10 years.

CEPA brought industry experts together in 2014 to create a metal-loss ILI tool validation guidance document, which provides transmission pipeline companies with a process to validate whether in-line inspections are done correctly. Doing this assessment provides transmission pipeline operators increased confidence in the data collected and their subsequent decisions on whether additional action, such as an integrity dig, needs to be taken.

External Leak Detection Experimental Research (ELDER) test apparatus

In 2013, CEPA members Enbridge and TransCanada joined forces to conduct ground-breaking research in the area of leak detection by using a state-of-the-art pipeline simulator known as the External Leak Detection Experimental Research (ELDER) test apparatus. Developed by Enbridge and project partner C-FER Technologies, the ELDER test apparatus allows researchers to evaluate external leak detection technologies in a setting that very closely represents the actual conditions where liquids pipelines are installed.

TransCanada, Enbridge, Kinder Morgan Canada and the Alberta Ministry of Innovation and Advanced Education are also now funding research to test new leak detection technologies, such as vapour-sensing tubes, fibre-optic distributed temperature-sensing systems, hydrocarbon-sensing cables and fibre-optic distributed acoustic-sensing systems.

By using waste heat recovery technology

Using waste heat recovery technology, pipeline companies can reduce their own energy needs or make the electricity available to others – supplying it to industries located near the pipeline

One environmentally-friendly and sustainable practice is the process of waste heat recovery. Technology that can take the heat The pipeline industry uses heat recovery systems that capture the excess heat emitted from compressors and turn it into clean energy that can be re-used. It’s technology that captures the heat and uses it to produce electricity, without requiring additional fuel or generating emissions. Once the heat is captured by a heat exchanger, it’s used to heat up pressurized water or organic liquids to liquids that boil at a lower temperature than water and vaporize and expand when heated. The pressurized steam or vapor produced by the liquid is used to generate electricity, and then it’s cooled and re-used. The electricity produced by this process can be used by other industries that are located near the pipeline compressor station, or can be provided to the electricity grid. Waste heat recovery is an innovative process and the pipeline industry is focused on developing other ways to use it, including creating smaller heat recovery units. This focus is part of the industry’s commitment to reducing environmental impacts and providing a reliable source of clean, emission-free energy. The procedure can be shown in Figure 53.

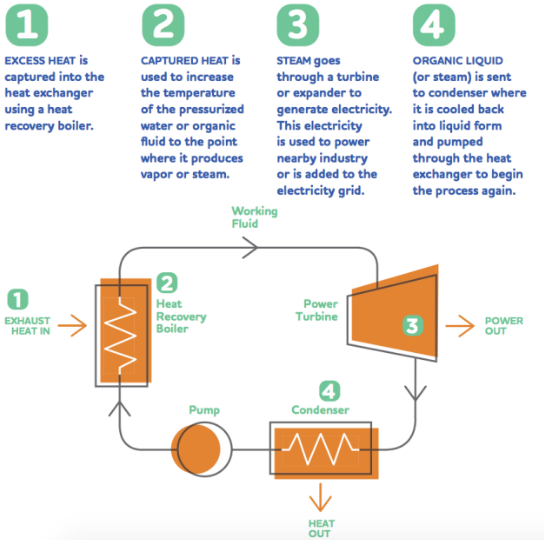


Figure 53. Waste heat recovery technology

4.8.2. Efforts of Pipeline companies coping with GHG emissions

Pipeline companies coping with climate change

CEPA members, Who operate Canada’s transmission pipelines, are responsible for one per cent of the country’s total emissions. Pipelines transport natural gas and liquid hydrocarbons, such as oil, from supply basins to various areas here they are used to heat homes and businesses, provide fuel for our cars and manufacture items for our daily lives. Greenhouse gas emissions from liquids pipelines are very small compared with natural gas pipelines. There are two main ways natural gas pipelines emit greenhouse gases: from burning fossil fuels at compressor stations and methane from small leaks or maintenance activities. To transport gas over long distances, natural gas pipeline operators use compressor stations with turbines and engines to push the products through the pipeline – this process emits carbon dioxide and nitrous oxide. Companies use a variety of techniques to limit the amount of greenhouse gases released, including: Upgrading equipment to be more energy-efficient.

Adopting technologies that divert or capture the release of natural gas during maintenance. Decreasing the amount of methane released from small leaks in the pipe is another way the industry is reducing emissions. CEPA members are using technologies that detect small leaks, including portable gas detectors and ultrasonic detectors, so the leaks can be repaired. Beyond operations, many CEPA members have climate change and environmental sustainability programs to track, address and manage their emissions. CEPA members will continue to adopt practices, programs and technologies to limit and reduce their greenhouse gas emissions.

Pipeline industry protect Canada’s rivers, streams and lakes

One of the most important considerations is choosing the best location for the pipeline to cross. It’s critical the selected route maintains the stability and quality of the pipeline to protect the surrounding environment. Soil erosion, the stability of the slopes and banks, and even the bends in a river or stream, are just some of the factors pipeline operators analyze when choosing the route. Allowing operators to access the pipeline to do maintenance and inspections is also important. To choose the most effective, least impactful route, pipeline operators may have to study the location of the route for several seasons before construction begins, especially if the watercourse has a seasonal flow or there is the potential for impact on the environment. Two main methods are used for installing a pipeline across water: digging a trench or using trenchless methods. If the surrounding land and banks are stable enough, pipeline operators try to use trenchless methods. Whichever method is selected, operators carefully review the potential impacts to wildlife, vegetation and soil and try to avoid any disruption during construction. This includes reviewing the environmental risk, considering alternative crossing methods and meeting with landowners and the local stakeholders to understand any additional risks. The installation of a pipeline in a body of water is carefully monitored to maintain the surrounding environment. For instance, operators must minimize the use of equipment within the perimeter of crossing so as to avoid transferring noxious weeds or invasive plant species into the area.

Pipeline operators manage emissions from storage tanks

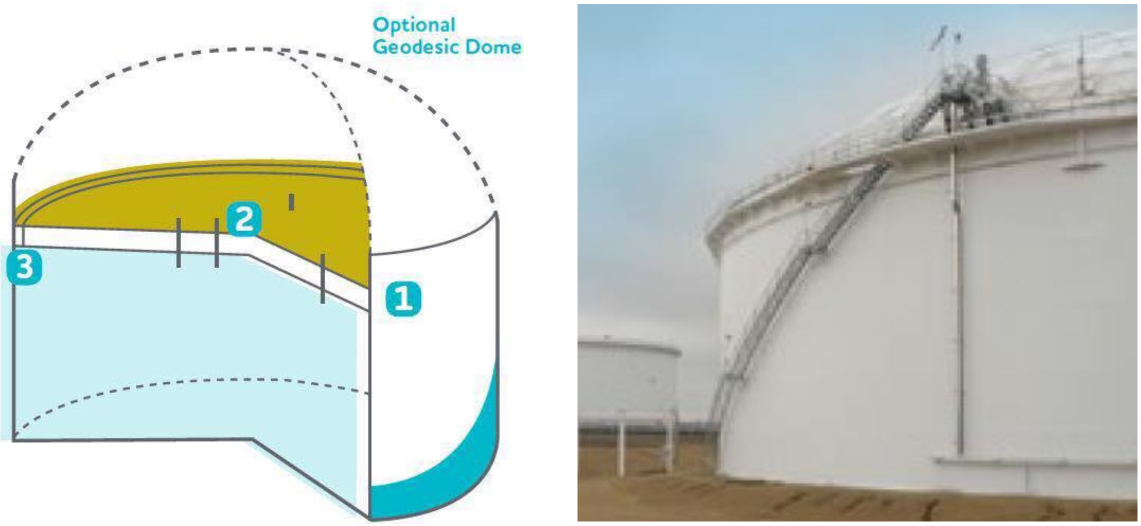


Figure 54. Storage tanks

- THE COLOUR: Tanks are often painted white to reduce heat being absorbed by the sun and prevent the stored liquids from evaporating.
- THE ROOF: Storage tanks have floating roofs, which sit on top of the liquid to decrease the amount of air space in the tank and prevent evaporation. The roof moves up and down as the tank is filled and emptied.
- THE SEALS: The floating roof has primary and secondary seal systems that create vapour-tight barriers between the roof and walls of the tanks to minimize the release of emissions.

Natural gas pipeline operators do about their methane emissions

The source: unintentional pipeline leaks Sometimes small leaks can happen from the pipeline, equipment and instrumentation, either above or below ground. It’s estimated that 80 per cent of emissions are often contributed by 10 to 15 per cent of detected leaks.

The solution: ongoing maintenance Pipeline operators have thorough maintenance plans to regularly check equipment and make repairs. This could include replacing seals or regularly changing the packing material around the compressor's rods to prevent any residual gas from escaping during operation.

4.8.3. Technologies of emission reductions

Reduce Emission with Economic Rod Packing Replacement

(1) Reducing Emissions from Compressor Seals

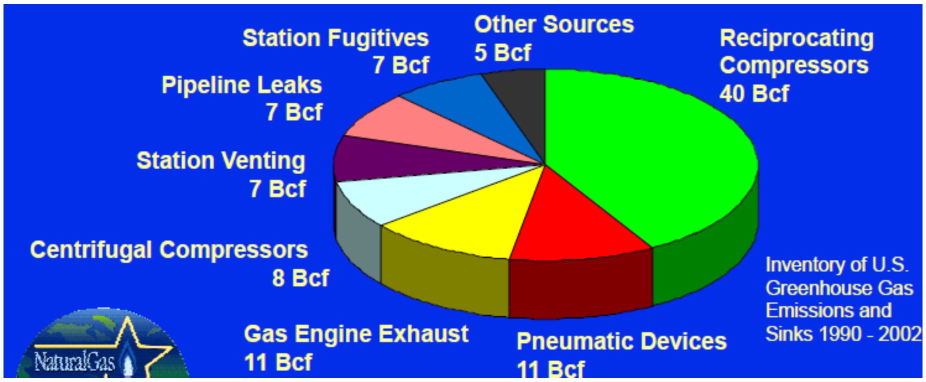


Figure 55. Methane losses from transmission and storage

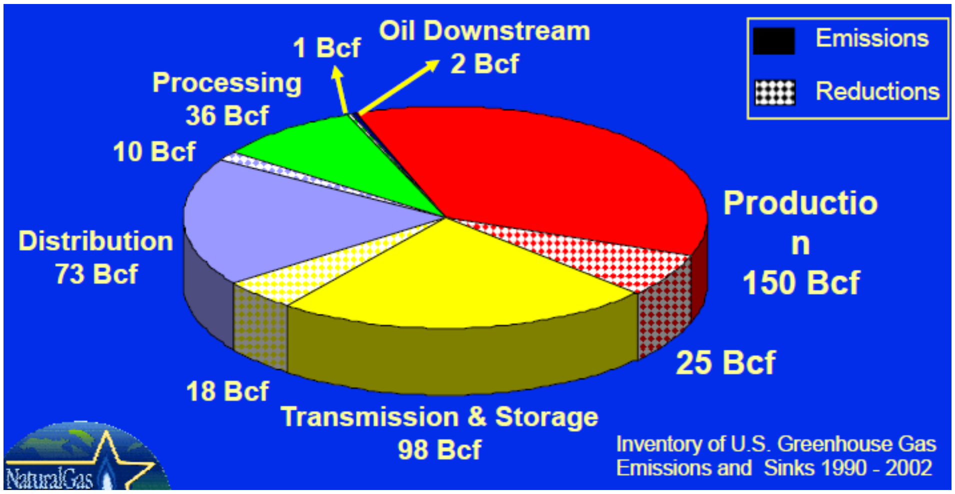


Figure 56. Methane losses from production

In Figure 55, compressor seals contribute 50% of transmission and storage emission, 40 Bcf from reciprocating compressors and 8 Bcf from centrifugal compressors. Production responsible for 42% of methane emissions as shown in Figure 56. Compressor seals account for 13% of natural gas industry emissions. Over 45,000 compressors in the natural gas industry, over 8,500 compressors in gas transmission sector.

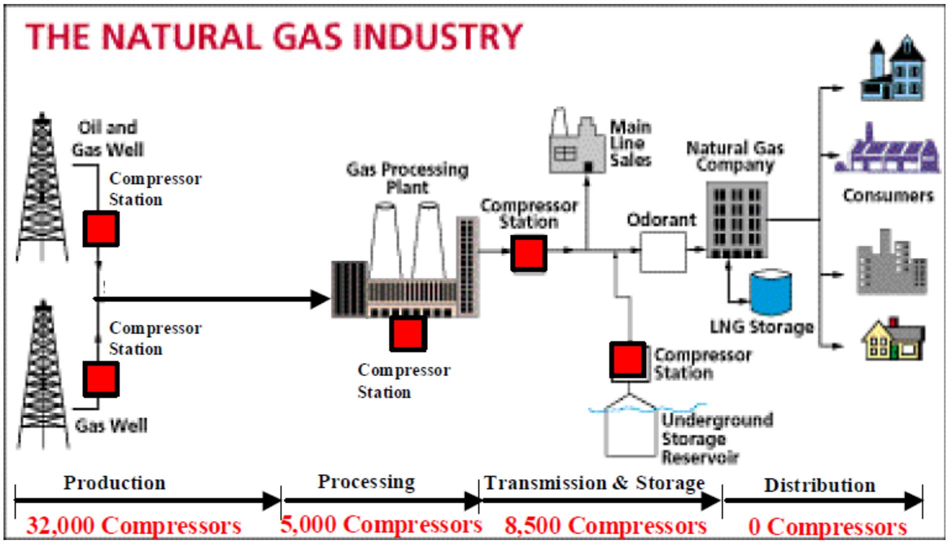


Figure 57. The natural gas industry

Reciprocating compressor rod packing leaks some gas by design. Newly installed packing may leak 60 cubic feet per hour (cf/h), worn packing has been reported to leak up to 900 cf/h.

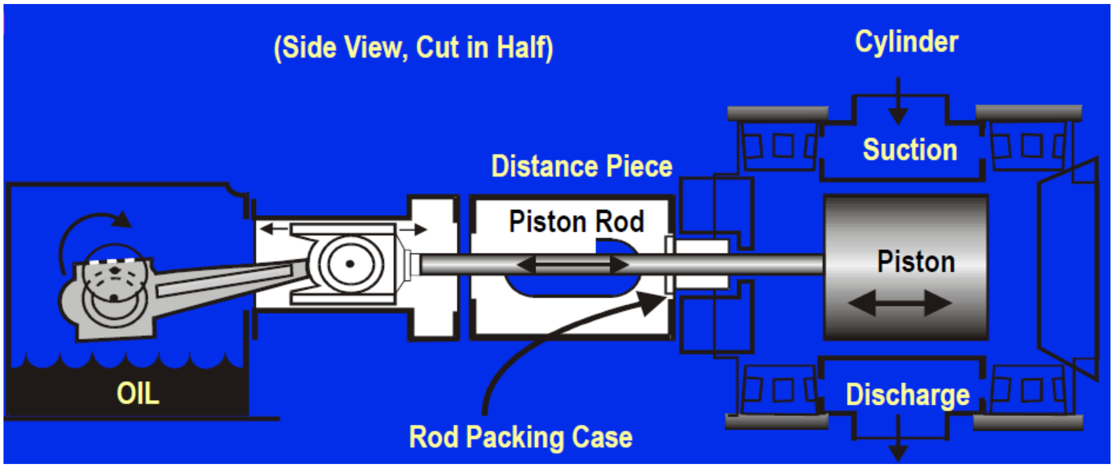


Figure 58. Reciprocating compressors

Reciprocating Compressor Rod Packing. A series of flexible rings fit around the shaft to prevent leakage. Leakage still occurs through nose gasket, between packing cups, around the rings and between rings and shaft.

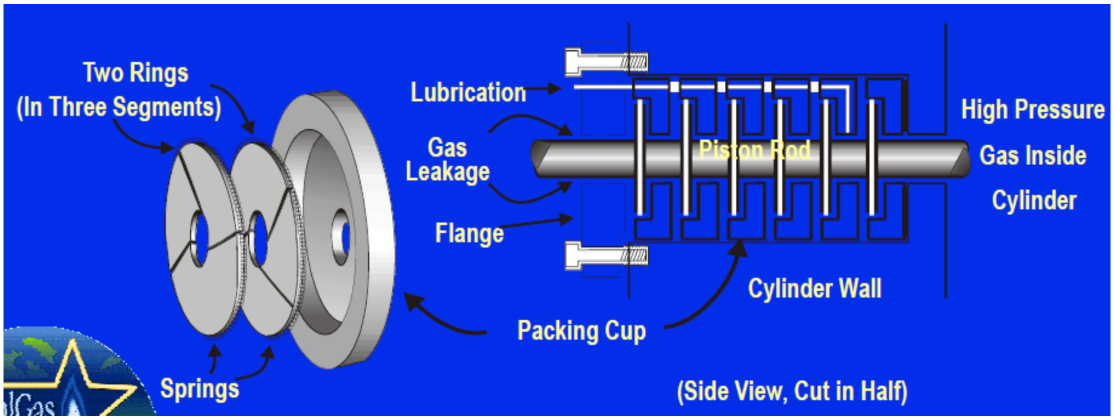


Figure 59. Reciprocating compressor rod packing

Decision Process: Monitor and record baseline packing leakage and piston rod wear, Compare current leak rate to initial leak rate to determine leak reduction expected, Assess costs of replacements, Determine economic replacement threshold, Replace packing and rods where cost-effective.

(2) Methane Recovery Through Economic Rod Packing Replacement

Step 1: Monitor and record baseline leakage and rod wear

- Establishing baseline leak rates and monitoring rod wear can help to track leakage and evaluate economics.

Step 2: Compare current leak rate to initial leak rate to determine leak reduction expected

- Leak Reduction Expected (LRE) = Current Leak Rate (CL)– Initial Leak Rate (IL)
- Example: The current leak rate is measured as 100 cf/h, the same component leaked 11.5 cf/h when first installed

LRE = 100 cf/h – 11.5 cf/h

LRE = 88.5 cf/h

Step 3: Assess costs of replacements

- A set of rings: $500 to $800
- (with cups and case) $1500 to $2500
- Rods: $1800 to $3500

Step 4: Determine economic replacement threshold

- Partners can determine economic threshold for all replacements
- Economic Replacement Threshold (scfh) $= \frac{\mathrm{CR}*\mathrm{DF}*1000}{(H*GP)}$

$$DF = \frac{i\ (1+\mathrm{i})^{n}}{(1+i)^{n}-1}$$

Where,
CR=Cost of replacement($)
DF=Discount factor (%) @ interest i
H=Hours of compressor operation per year

GP=Gas price ($/Mcf)

Step 5: Replace packing and rods when cost-effective

◆ **Example:** Rings Only

Rings: $1,200
Rod: $0
Gas: $3/Mcf
Operating: 8,000 hrs/yr

Leak Reduction Expected (scfh)	Payback Period (yrs)
55	1
29	2
20	3
16	4
13	5

Rod and Rings

Rings: $1,200
Rod: $7,000
Gas: $3/Mcf
Operating: 8,000 hrs/yr

Leak Reduction Expected (scfh)	Payback Period (yrs)
376	1
197	2
137	3
108	4
90	5

Based on 10% interest rate
Mcf = thousand cubic feet, scfh = standard cubic feet per hour

Figure 60. Example of replace packing and rods when cost-effective

Reduce Emissions with Dry Seals Replacement

Methane Losses from Centrifugal Compressors. Centrifugal compressor wet seals leak little gas at the seal face. Seal oil degassing may vent 40 to 200 cubic feet per minute (cf/m) to the atmosphere. A Natural Gas STAR partner reported wet seal emissions of 75 Mcf/day (52 cf/m).

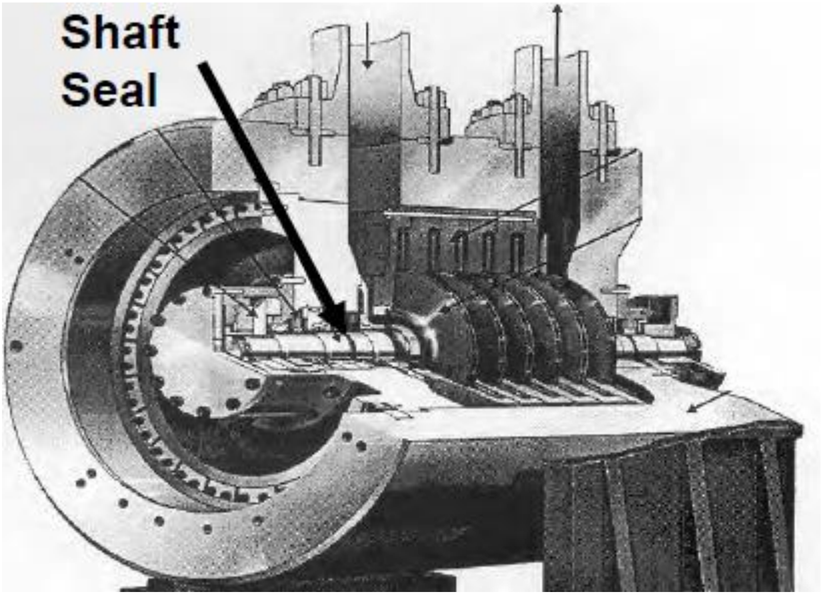


Figure 61. Centrifugal compressors

(1) Centrifugal Compressor Wet Seals

High pressure seal oil is circulates between rings around the compressor shaft. Gas absorbs in the oil on the inboard side. Little gas leaks through the oil seal. Seal oil degassing vents methane to the atmosphere.

Dry seal springs press the stationary ring in the seal housing against the rotating ring when the compressor is not rotating. At high rotation speed, gas is pumped between the seal rings creating a high pressure barrier to leakage. Only a very small amount of gas escapes through the gap 2 seals are often used in tandem.

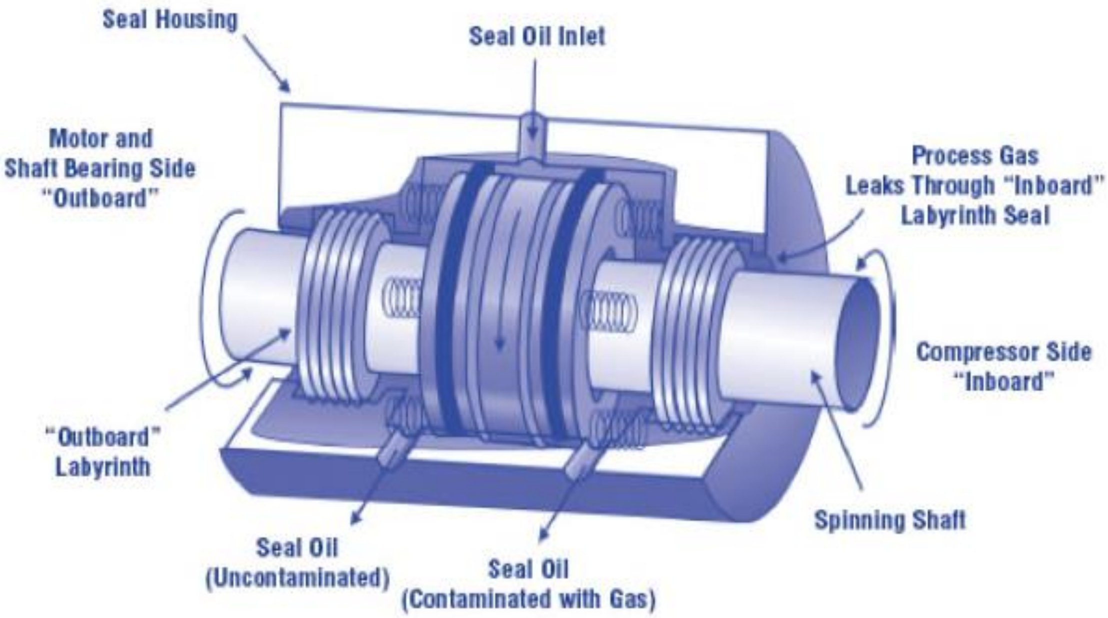


Figure 62.Wet seal

Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the compressor casing. The more common "beam" type compressors have two seals, one on each end of the compressor, while "over-hung" compressors have a seal on only the "inboard" (motor) side. These seals use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. "O-ring" rubber seals prevent leakage around the stationary rings. Very little gas escapes through the oil barrier; considerably more gas is absorbed by the oil under the high pressures at the "inboard" (compressor side) seal oil/gas interface, thus contaminating the seal oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The recovered methane is commonly vented to the atmosphere.

(2) Methane Recovery with Dry Seals

Dry seals typically leak at a rate of only 0.5 to 3 cf/m. Significantly less than the 40 to 200 cf/m emissions from wet seals. These savings translate to approximately $48,960 to $279,360 in annual gas value.

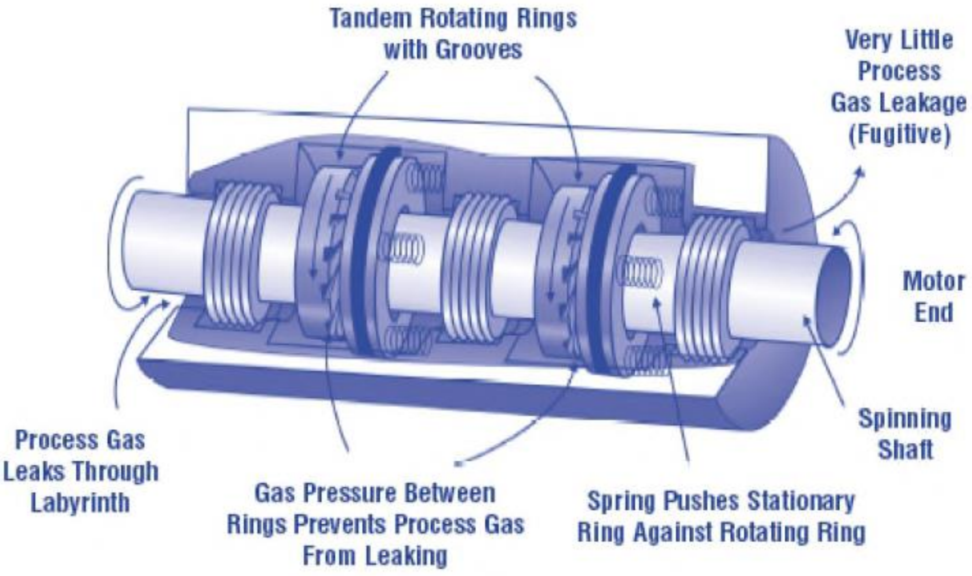


Figure 63. Dry seal

An alternative to the traditional wet (oil) seal system is the mechanical dry seal system. This seal system does not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and static pressure. Hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This gas is pumped between the rings by grooves in the rotating ring.

The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little gas can leak. While the compressor is operating, the rings are not in contact with each other, and therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.

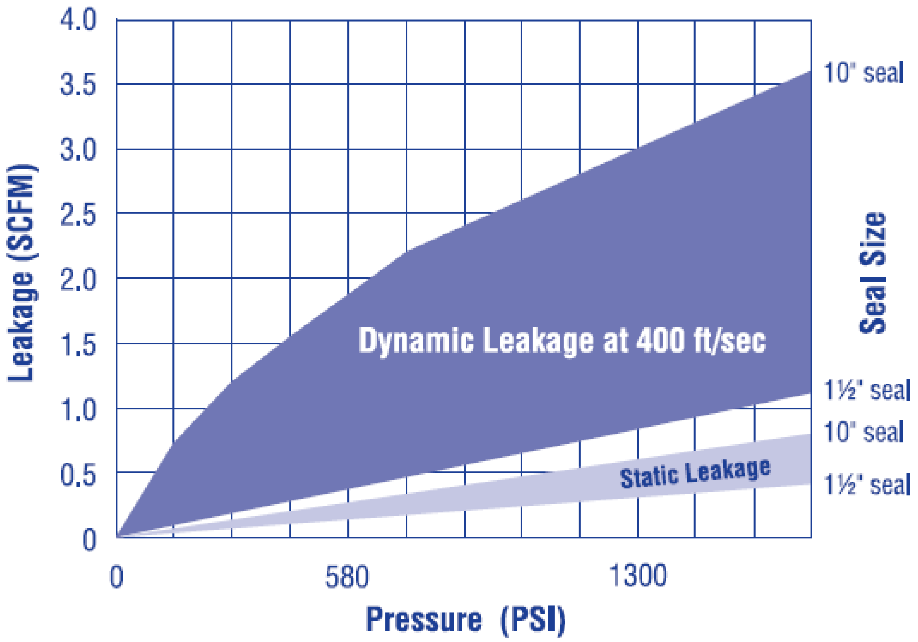


Figure 64. Dry seal performance chart

Other Benefits with Dry Seals: Aside from gas savings and reduced emissions, dryvseals also:

- Lower operating cost
- Dry seals do not require seal oil make-up
- Reduced power consumption
- Wet seals require 50 to 100 kiloWatt hours (kW/hr) for ancillary equipment while dry seals need only 5 kW/hr
- Improve reliability
- More compressor downtime is due to wet seals
- Eliminate seal oil leakage into the pipelines
- Dry seals lower drag in pipelines (and horsepower to overcome)

Reduce Emissions with Dry Seal Replacement:
Step 1: Identify candidates for replacement.
Dry seals are routinely used for compressors operating up to 1,500 pounds per square inch (psi), up to 400 Fahrenheit

Step 2: Estimate savings from a dry seal

- Gas savings between 34 to 196 cf/m
- Other dry seal benefits ≈ $63,000/yr
- Reduced seal power losses=$13900
- Reduced oil pump/fan losses=$4000
- Increase pipeline flow efficiency =$26600
- Reduced oil losses=$3500
- Reduced O&M, downtime= $15000

Step 3: Determine dry seal conversion costs

- Dry seals cost $5,000 to $6,000 per inch of shaft diameter or $8,000 to $10,000 for tandem seals
- Beam compressors require two seals, one at each end
- Overhung compressors require one seal at the inboard end

Step 4: Compare costs and savings for a 6-inch shaft beam compressor

Table 76. Compare costs and savings for a 6-inch shaft beam compressor

Cost Category	Dry Seal ($)	Wet Seal ($)
Implementation Costs		
Seal costs (2 dry @ $10,000/shaft-inch, w/testing)	120,000	
Seal costs (2 wet @ $5,000/shaft-inch)		60,000
Other costs (engineering, equipment installation)	120,000	0
Total Implementation Costs	240,000	60,000
Annual O&M	10,000	73,000
Annual methane emissions[4] (@ $3.00/Mcf; 8,000 hrs/yr)		
2 dry seals at a total of 6 scfm	8,640	
2 wet seals at total 100 scfm		144,000
Total Costs Over 5-Year Period ($):	333,200	1,145,000
Total Dry Seal Savings Over 5 Years:		
Savings ($)	811,800	
Methane Emissions Reductions (Mcf) (at 45,120 Mcf/yr)	225,600	

5. Carbon Tax Impacts Analysis

5.1. Overview of carbon tax scenarios

Canada targets to achieve an economy-wide emissions objective by reducing its GHG emissions 30% below 2005 levels by 2030. As planned, in 2018, a national carbon price will be imposed on all of Canada. The initial price will be a minimum of C$10 per tonne of CO_2 and it will be increased annually by C$10/tonne to reach C$50 in 2022. Moreover, Canada has some special characteristics in terms of its production structure and energy use patterns. In 2016, the Canadian economy was estimated to have nearly equivalent net exports of minerals and fuels (i.e., 16 percent of GDP) and automobiles (i.e., 16.4 percent of GDP). Mineral and fuel production tend to be concentrated in Western Canada provinces (i.e., Alberta, and Saskatchewan, and to some extent British Columbia), while Canadian manufacturing exports tend to come from Central Canada (i.e., Quebec and Ontario). Manufacturing economies can adjust to carbon pricing and taxation by passing on costs to customers, but revenues in natural resource-based economies are determined by global commodity markets.

The Province of Saskatchewan's economy largely relies on resource extraction. The total value of mineral sales (i.e., oil, potash, and uranium) was $12.8 billion in 2016. The potash production increased to 10.9 million tonnes with over half of Saskatchewan's potash exports going to Brazil, Indonesia, China, and India. High oil prices motivated accelerated drilling activities within the province before 2014. In 2016, Saskatchewan produced 26.7 million cubic meters of oil, which is affected by the oil industry itself. Agriculture is another pillar industry in Saskatchewan. According to the 2016 Census of Agriculture, Saskatchewan accounted for more than two-fifths of Canada's total field crop acreage with 36.7 million acres. In Saskatchewan's energy system, crude oil plays an important role, while the production of natural gas liquids is relatively low. Coal also accounts for a significant portion of Saskatchewan's energy utilization, with most of the production is used for electricity generation in the Province. Renewable energy, such as hydropower, wind power, is also used for electricity generation, but is currently available at higher unit costs.

In October 2016, the Government of Canada published the Pan-Canadian Approach to Pricing Carbon Pollution to ensure that carbon pricing applies to a broad set of emission sources throughout Canada in 2018 with increasing stringency over time. Under the benchmark, provinces and territories can implement the type of carbon pricing system that makes sense for their circumstances. As part of the benchmark, the federal government also committed to implement a federal carbon pricing backstop that will apply in any province or territory that requests it or that does not have a carbon pricing system in place in 2018 that meets the benchmark.

In May 2017, the federal government released a Technical Paper on the Federal Carbon Pricing Backstop outlining the federal carbon pricing backstop with two elements: 1) a charge on fossil fuels that is generally payable by fuel producers or distributors, with rates that will be set for each fuel such that they are equivalent to $10 per tonne of carbon dioxide equivalent in 2018, rising by $10 per year to $50 per tonne in 2011, and 2) an output-based pricing system for industrial facilities.

The aim of the OBPS is to minimize competitiveness risks for emissions-intensive, trade-exposed industrial facilities, while retaining the carbon price signal and incentive to reduce GHG emissions. The charge is not intended to apply to fuel used at a facility that is part of the OBPS. Each OBPS facility will instead be subject to the carbon price on the portion of emissions that exceed an annual output-based emissions limit. In jurisdictions where the backstop applies, the OBPS will apply to industrial facilities that emit 50 kt carbon dioxide or more and for which an output-based standard is specified, or that emit between 10 and 50 kt carbon dioxide per year and whose application for voluntary participation is approved.

Industrial facilities that are registered under the OBPS will be able to purchase charge-free fuel from the time the charge starts to apply. OBPS facilities will instead be subject to the carbon price on the portion of their emissions that exceed an annual output-based emissions limit. An OBPS facility's annual GHG emissions limit, expressed in tonnes of carbon dioxide, will be based on the prescribed output-based standards (OBS) for the production activities that the facility undertakes. The limit for a single product facility will be determined by multiplying the applicable output-based standard and the facility's total annual production. For a facility to which more than one output-based standard applies, the annual facility emissions limit will be based on the sum of the limits for each product.

Covered emission sources will include fuel combustion, industrial process, flaring, and some venting and fugitive sources. Methane venting and methane fugitive emissions from oil and gas facilities will not be subject to pricing under the OBPS. Emissions of all seven of the UNFCCC greenhouse gases will be included, to the extent practicable – carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and nitrogen trifluoride.

Saskatchewan has a demonstrated, long-standing commitment to action on climate change. Between 2008 – 2015, the Government of Saskatchewan invested $60 million in GoGreen funding through public-private partnerships to reduce greenhouse gas emissions, enhance biodiversity and educate the public about the effects of climate change. Saskatchewan did not sign the subsequent Pan-Canadian Framework on Clean Growth and Climate Change, in large part because the Framework promotes a carbon tax as the central approach to reducing emissions. A carbon tax would not significantly reduce emissions in our province where our economy and geography don't allow for easy alternatives. In fact, a carbon tax would make it more difficult for our province to respond effectively to climate change because a simple tax will not result in the innovations required to actually reduce emissions. We believe the challenges we face are complex and will not yield to simple measures.

In 2017, the Government of Saskatchewan proposed the A Made-in-Saskatchewan Climate Change Strategy. In this strategy, the Government of Saskatchewan builds upon actions we have already taken and introduces measures to strengthen our province and build resilience to climate change. Our plan is bold, broad and made for Saskatchewan. It is the best way for our province to harness our valuable resources while contributing solutions to an issue that affects the entire world.

Resilience is key to Saskatchewan's approach to climate change. Resilience is the ability to cope with, adapt to and recover from stress and change. This is essential, as some effects of climate change are already underway and unavoidable. Resilience is a much stronger indicator of effective climate action than simply measuring reductions in greenhouse gas emissions, because it measures our overall ability to adapt, innovate and even thrive.

Saskatchewan has strong motivation to seek solutions. We have recently endured many varied and costly climate-related events and are acutely aware of our exposure to changing climate because the land is integral to our economy. Our province is expected to experience more extreme weather events, including an increase in the severity and frequency of droughts and flooding, and more intense forest fires. For Saskatchewan, climate change resilience is critical. Multiple systems need to be strengthened to improve the resilience of the province as a whole. This includes the ability of Saskatchewan's natural systems (including our land, water, and forests), infrastructure, communities and economy to adapt and thrive in a changing, low-carbon economy.

Therefore, the carbon tax will be applied in two sectors, which are transportation and building sectors. According to the announcement of the Government of Canada, the floor price will start at $10 a tonne in 2018, and go up by $10 a year for the next four years," and "reach a minimum of $50 a tonne by 2022. The carbon tax scenario in this section is show in Table 77.

Table 77. Dynamic carbon tax scenario

Year	Carbon Tax
2018	$10/tonne
2019	$20/tonne
2020	$30/tonne
2021	$40/tonne
2022	$50/tonne
2023	$50/tonne
2024	$50/tonne
2025	$50/tonne
2026	$50/tonne

Once a more representative price has been set for carbon, whether through carbon tax or cap and trade, new revenue becomes available to be put to use. This carbon revenue needs to be recycled or reinvested to enable us to change our behavior, technology, systems, and infrastructure so that we emit less greenhouse gases (GHG) every day. How the government chooses to recycle carbon revenue is the biggest challenge and the biggest opportunity. These choices can result in a program that is truly effective in reducing emissions while still maintaining (or growing) the economy.

Transfer to households is one potential and most accepted revenue recycling mechanism. This could be an annual cheque paid directly to citizens. It may be equal for all or adjusted for income.

The advantages of transfer to households include fairness issue, highly progressive, highly transparent, and support building. However, it cannot provide any economic or environmental benefits.

In this section, we model the carbon tax scenario, and also represent the revenue recycling scheme as transfer to households. When simulating the carbon tax recycling scenario, the carbon tax revenue will be transferred to the households as government transfer at the end of every year. Then, the next round of simulation will continue after this transfer.

To compare the variances among different carbon tax mechanism, the carbon tax impacts on marco economy, GDP decomposition analysis, and impacts on detailed sectors will be discussed. In the following sub-sections, there are 3 scenarios as listed in Table 78.

Table 78. Carbon tax scenarios

Scenario	Sectors	Revenue recycling
1	All	None
2	Transportation & building	None
3	Transportation & building	Transfer to households

Energy was not identified as input factors in Statistic Canada’s IO tables. Five raw energy mining and electric power generations were embedded in different sectors in IO tables. To isolate these factors as an input, we followed Wolsky’s method to disaggregate these sectors into single sector. This process was described in the methodology section. The final model sector are defined in Table 79.

A host of parameters were required in the model. Endogenous parameters including share and efficiency parameters were calibrated using input data. Elasticities of substitution in the composite value-added function and income elasticities of demand for commodities are obtained from other literatures. Armington, CET elasticities and import tariffs were derived from GTAP database following sectoral aggregation. Due to lack of provincial and sector-specific data, we assumed that the elasticities for all sectors are the same.

The employment rate data for Saskatchewan were obtained from provincial labor force survey estimates. We estimated the mean annual rates across all age groups from the seasonally adjusted monthly rates. We didn’t disaggregate the labor into different groups due to the limitation of the data sources.

Table 79. Sector definition

Sector Mnemonics	Sector Definition
C	Consumer
G	Government
I	Investment
STO	Stocking
EX	Export
IM	Import
CAP	Crop and animal production
FRL	Forestry and logging
FHT	Fishing, hunting and trapping
SAA	Support activities for agriculture and forestry
OEX	Oil extraction
GEX	Gas extraction
CAM	Coal mining
OMQ	Other mining, quarrying
FFE	Fossil-fuel electric power generation
CEE	Clean electric power generation
NGD	Natural gas distribution
OTU	Other utilities
CON	Construction
PER	Petroleum refineries
OTM	Other manufacturing
TRA	Trade
TRP	Transportation
WAS	Warehousing and storage
SER	Services
PUB	Public administration

The model was formulated as static and solved recursively over nine-year period. For every year, capital stock was updated via a capital accumulation equation based on an endogenous growth rate as determined by endogenous return on capital rate and endogenous total savings. Although the GDP of Saskatchewan has decreased 5.6% in 2014, the average growth rate of GDP is 1.6% during 2011 to 2015. In this study, we choose 1% as the projection growth rate.

Labor was assumed to grow exogenously in the model. Labor supply growth projections were estimated using projected population trends. We estimated average annual growth rates between 2016 and 2017 from the medium growth projection scenario for both sexed and all ages' category, as the most representative of future population trends. This was thought to be the safe middle ground between the lowest and highest projected population growth rate trends categories, hence moderate for uncertain future trends. In this model, we use 1.3% as the growth rate of labor force.

The model was solved using the General Algebraic Modeling System (GAMS) software with the PATH algorithm along with MPSGE solver (GAMS, 2012). After solving the model for the initial period to replicate the 2011 benchmark IO tables, a dynamic baseline growth path of the economy was simulated in the model by allowing labor and capital to grow as described earlier. Economic variables under this Baseline scenario can be compared to the carbon tax scenario.

5.2. Impacts on Marco economy

The provincial economies were further aggregated and disaggregated into 20 sectors following the Northern America Industry Classification System (NAICS 2002 version), which is the most detailed that could be obtained from Statistics Canada. As mentioned previously, three primary factors of production were specified, including labor, capital, and energy. Labor was measured (using Statistics Canada IO tables) as wages, salaries and supplementary labor income, in addition to "mixed income" (i.e., income of unincorporated businesses). Capital was estimated (also using Statistics Canada IO tables) as the sum of other operating surplus, indirect taxes on products, subsidies on products, other subsidies on production, and other indirect taxes on production less land services expenditures (described hereafter).

Using the CGE model developed in this paper, the implications of a carbon tax on GDP change under different policy scenarios were calculated, as shown in Figure 65. Since GDP is the most widely-accepted indicator to represent the macroeconomic condition, the GDP change shown reflects the impacts of carbon tax on marco economy in Saskatchewan. It is seen from this figure that the carbon tax has negative impacts on economic growth.

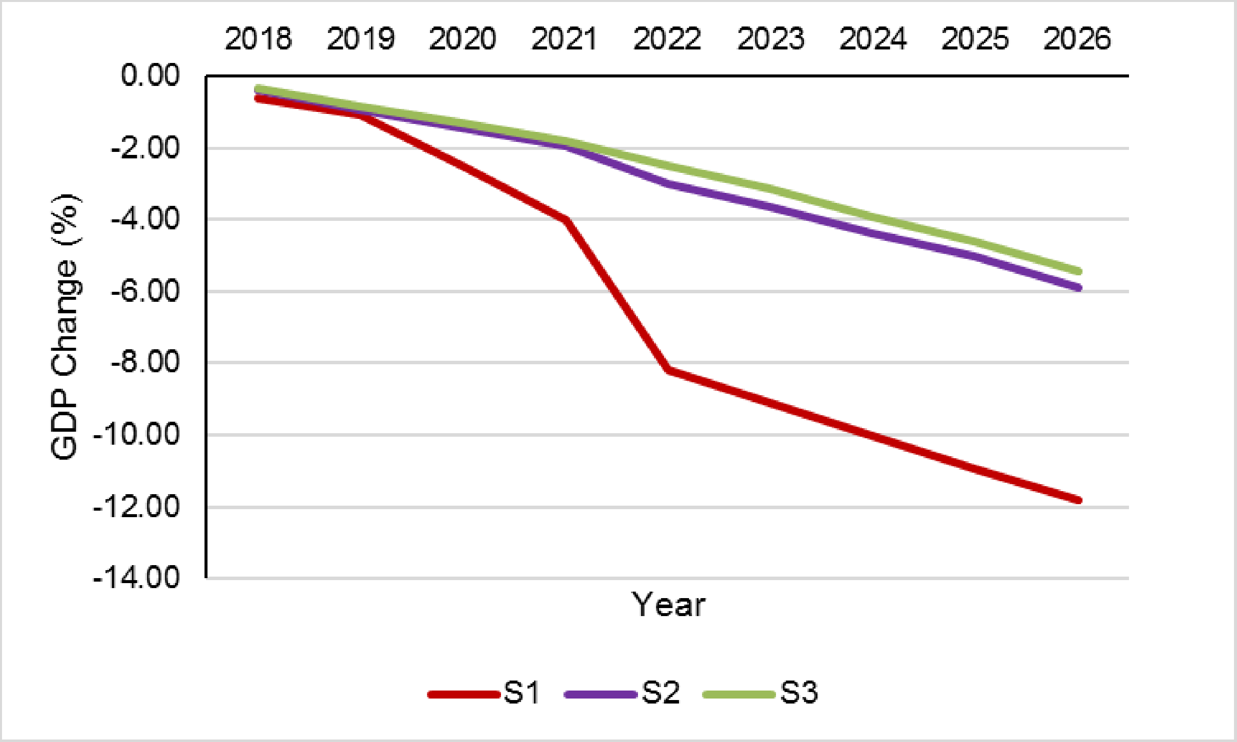


Figure 65. The impacts of carbon tax on GDP and GHG emission

The red line shows the GDP change under the dynamic carbon tax scenario, which will apply carbon tax on all industrial sectors with no revenue recycling mechanism. The GDP change between the carbon tax scenario and the baseline scenario quantified the inter relationship of carbon tax and economic growth. Due to the assumption that the GDP will increase 1% per year in the baseline scenario, the GDP change is much larger than the static CGE model. When carbon tax is under C$ 30 (i.e. 2018, 2019), the GDP change is relatively low. This indicates that a relatively low carbon tax won't hurt the economy too much. During 2020 to 2021, the GDP decrease faster when carbon tax continues to grow up. When carbon reaches C$ 40, the GDP will decrease 3.99%. What's more, the GDP will decrease sharply with the carbon tax equals to C$ 50. After 2022, the speed of GDP decrease become slower again, since the carbon tax stops grow up. At this stage, the economy has reached the equilibrium status when carbon tax is equal to C$ 50. The reason of the GDP reduction is mainly caused by the baseline increase. Considering that the GDP improvement of the Province of Saskatchewan was approximately 2% in 2015, the GDP change for scenario 1 would be considered unacceptable.

The purple line shows the GDP change between carbon tax scenario 2 and the baseline scenario. In scenario 2, the carbon tax will be applied only in transportation and building sector. As shown in this figure, the GDP reduction of scenario 2 is much smaller than the GDP change of scenario 1. When carbon tax is under C$ 30 (i.e. 2018, 2019), the GDP change is relatively low. This indicates that a relatively low carbon tax won't hurt the economy too much. During 2020 to 2021, the GDP continues to decrease along with the carbon tax increase. The trend of GDP change is similar with the red line. The difference is that there is no sharp decrease of GDP under scenario 2.

The benchmark gross output of transportation sector is 3825.5 million, with its emission equals to 3.3 million tonne. As analyzed previously, both export and import of this sector will change significantly with a carbon tax. Therefore, the GDP will still decrease in scenario 2. In addition, building sector is the only sector whose final demand is all capital formation. Thus, the import and export of building sector are almost zero, which will not be affected by the carbon tax. The characteristics of these two sectors are the main reason of the different trend of GDP change of scenario 2.

The green line shows the GDP change between carbon tax scenario 3 and the baseline scenario. In scenario 3, the carbon tax will be applied in transportation and building sector with the carbon tax revenue transferred to households at the end of every year. Comparing with other scenarios, the GDP change in scenario 3 are the smallest. This indicates that the revenue recycling mechanism have significant positive impacts on the marco economy.

As shown in this figure, the GDP reduction of scenario 3 has the same trend of GDP change of scenario 2. In 2026 (i.e. last year of simulation), the GDP reduction is -5.45%. While, the GDP reduction equals to -5.9% in scenario 2. The improvements are mainly caused by the household consumption improvement, since the household income will increase with the carbon tax revenue transfer.

Comparing the three scenarios, it can be seen that scenario 3 performs best with the smallest GDP reduction. However, the effects of carbon tax on GDP change is still obvious. There is no doubt that carbon tax is an effective way to reduce the GHG emissions. However, both environmental and economic targets should be considered simultaneously. It should be noted that in this section, only carbon tax has been simulated, while other emission reduction policies for different industries are ignored. The simulation results will be different once all the mitigation measures have been taken in to consideration, since all the industries all closely related in the entire socio-economic system. Therefore, in-depth analysis will be further conducted in the future study.

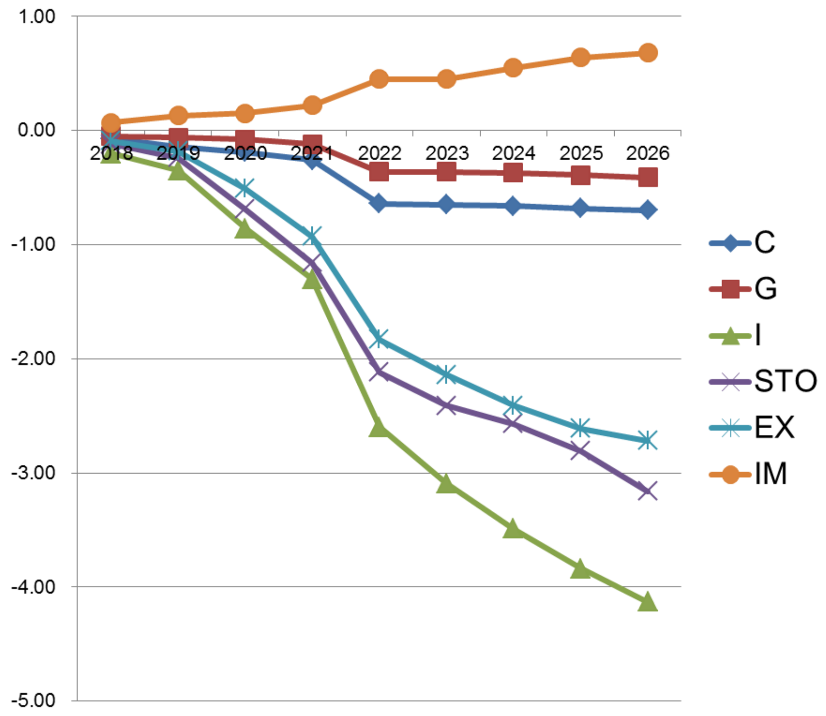
5.3. GDP decomposition analysis

Although GDP is one of the most widely-used macroeconomic indicators, there are many other macroeconomic variables that can reflect the impacts of carbon tax on macro economy. In this project, we calculated six macroeconomic variables under the three scenarios to better understand how the carbon tax affects the macro economy.

Since the real GDP is equal to the sum of household consumption, government consumption, total investment, total saving and stock, export and import, we calculated these six indicators to analyze the reason of the economy changes, as shown in Table 80.

Table 80. The GDP change decomposition of three scenarios

		2018	2019	2020	2021	2022	2023	2024	2025	2026
S1	C	-0.07	-0.14	-0.19	-0.26	-0.64	-0.65	-0.66	-0.68	-0.70
	G	-0.05	-0.06	-0.08	-0.12	-0.36	-0.36	-0.37	-0.39	-0.41
	I	-0.20	-0.35	-0.86	-1.30	-2.60	-3.09	-3.49	-3.84	-4.13
	STO	-0.12	-0.24	-0.69	-1.16	-2.12	-2.41	-2.57	-2.81	-3.16
	EX	-0.09	-0.18	-0.51	-0.93	-1.83	-2.14	-2.41	-2.61	-2.72
	IM	0.07	0.13	0.15	0.22	0.45	0.45	0.55	0.64	0.68
S2	C	-0.05	-0.11	-0.15	-0.21	-0.55	-0.58	-0.59	-0.61	-0.63
	G	-0.04	-0.05	-0.07	-0.10	-0.25	-0.28	-0.31	-0.33	-0.35
	I	-0.18	-0.33	-0.74	-0.95	-1.17	-1.32	-1.64	-1.86	-2.13
	STO	-0.09	-0.20	-0.39	-0.57	-0.81	-1.08	-1.33	-1.52	-1.95
	EX	-0.01	-0.05	-0.09	-0.14	-0.21	-0.37	-0.53	-0.70	-0.84
	IM	0.02	0.03	0.05	0.08	0.13	0.15	0.29	0.38	0.46
S3	C	-0.02	-0.05	-0.09	-0.15	-0.22	-0.30	-0.39	-0.48	-0.53
	G	-0.04	-0.05	-0.07	-0.09	-0.24	-0.27	-0.29	-0.30	-0.31
	I	-0.17	-0.30	-0.71	-0.90	-1.09	-1.21	-1.48	-1.73	-2.02
	STO	-0.09	-0.20	-0.37	-0.53	-0.76	-1.03	-1.26	-1.45	-1.81
	EX	-0.01	-0.05	-0.09	-0.13	-0.19	-0.34	-0.49	-0.65	-0.78
	IM	0.02	0.03	0.05	0.08	0.13	0.16	0.26	0.34	0.41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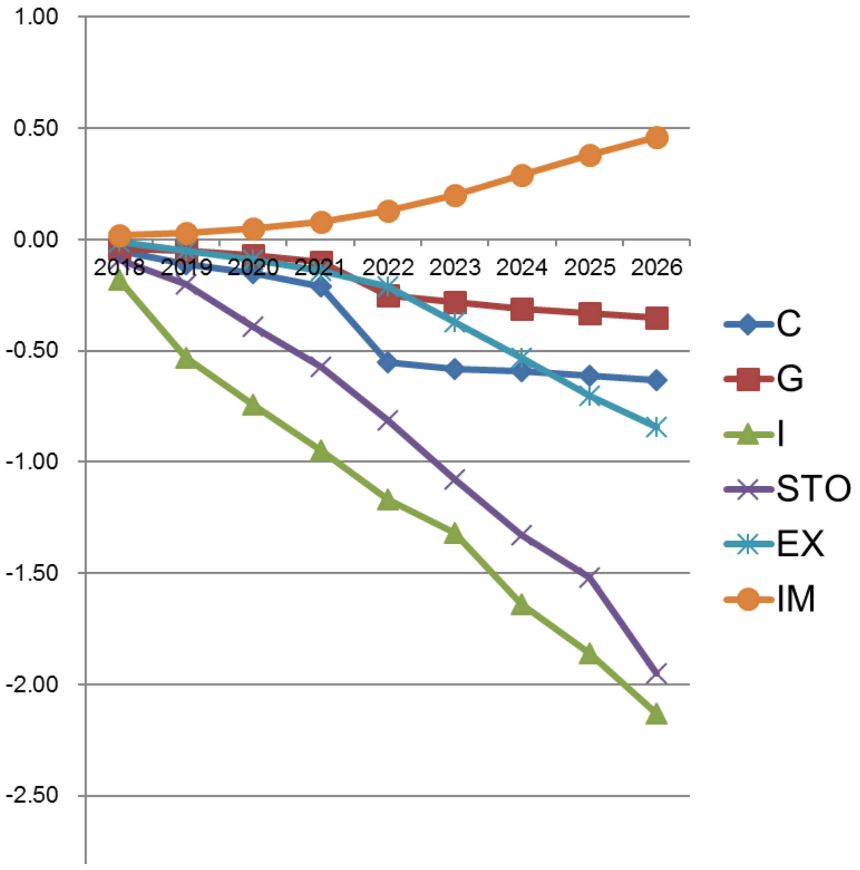
(a) S1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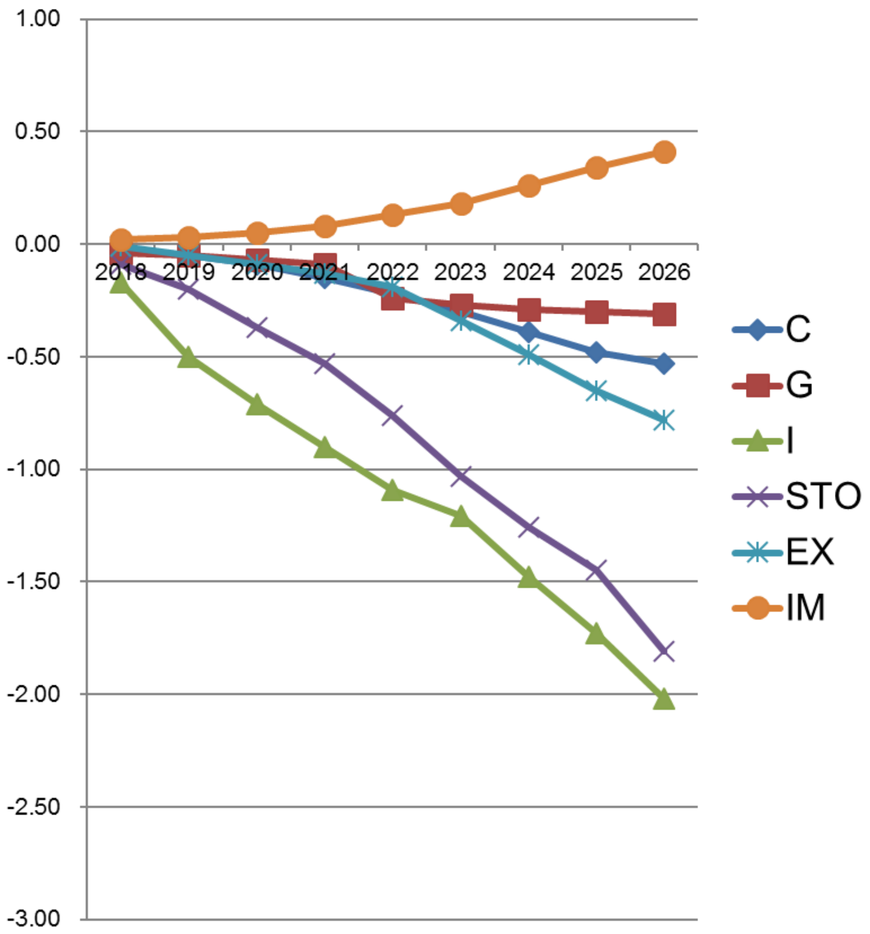
(b) S2



(c) S3

Figure 66. GDP decomposition of three scenarios

From Figure 66, we can see that the five macroeconomic indicators will decrease along with the GDP decrease, while import will increase. In addition, the changes of scenario 3 are the smallest, following by scenario 2, scenario 1.

Comparing the results of scenario 1 and scenario 2, it can be seen that the change degrees of six macroeconomic indicators varies significantly. Specially, the increase of export is most obvious. In addition, the increase of investment and stock are also significant.

When comparing the results of scenario 2 and scenario 3, different conclusions can be obtained. The export decrease degree and import increase degree are hardly changed. In the contrast, the household consumption increased obviously. At the same time, the investment, stock, and government consumption also increased with different degrees.

To better understand the changes of these six macroeconomic indicators, different comparison analysis have been conducted in this section. The changes of every indicators have been compared under three scenarios, as shown in Figure 67 to Figure 72.

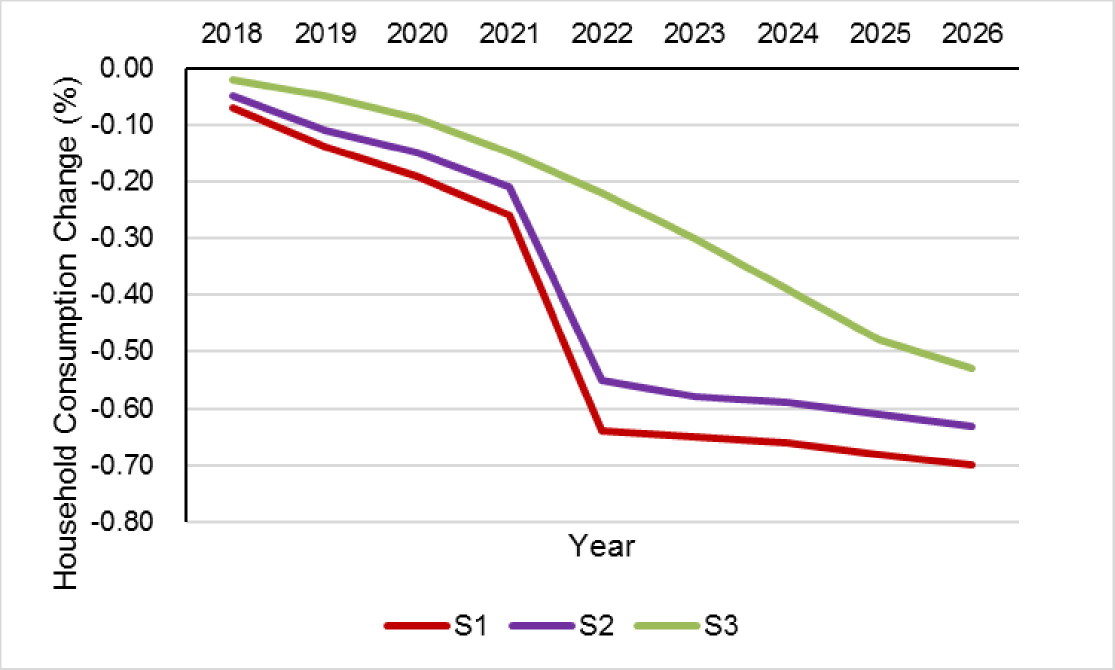


Figure 67. Household consumption changes

The household consumption will decrease with the carbon tax, as shown in Figure 67. This is mainly caused by the reduction of their incomes. The lowest demand of the household and government are determined by many variables, among which, the income is one important indicator.

When the carbon tax reaches C$40/tonne, household consumption will decrease by 0.25% in scenario 1. In scenario 2, the household consumption will decrease by 0.21%. This is mainly caused by the carbon tax application area. In scenario 3, the household consumption will decrease 0.15% due to the transfer payment from government. This further illustrate the benefits of carbon tax revenue recycling mechanism.

The lowest consumption demand of a household is determined by their income, which is mainly earned through labor inputs in the production activities. Thus, household income will decrease along with an economic depression, which will further lead to a consumption decline. As one of the carbon tax revenue recycling mechanism, transfer to household will increase the household consumption most obviously.

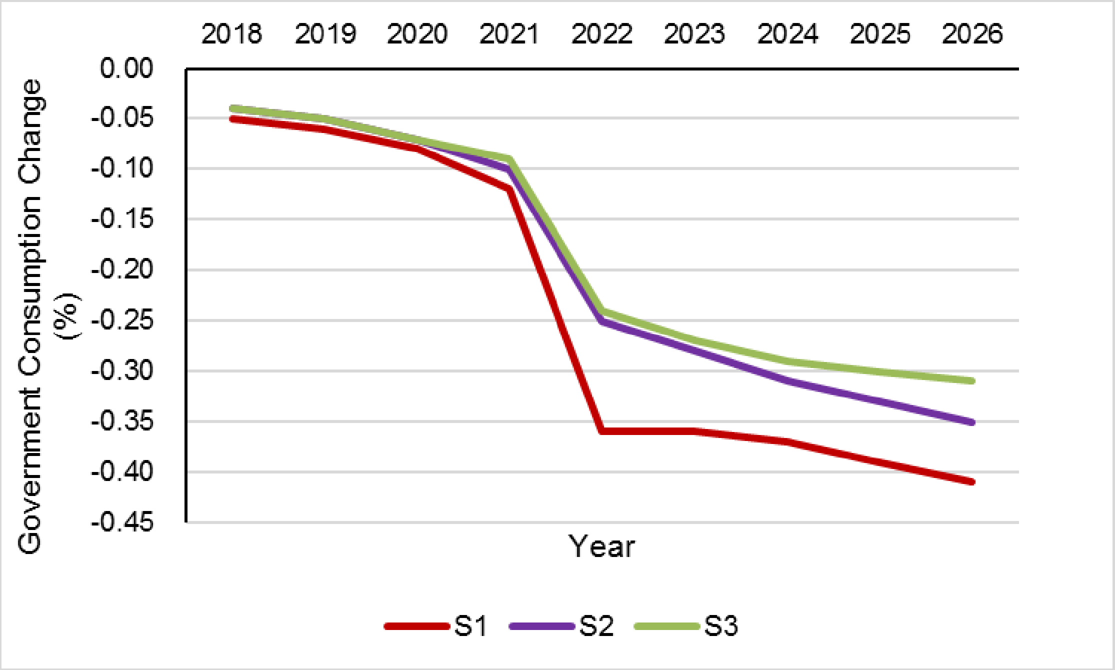


Figure 68. Government consumption changes

The government consumption will decrease with the carbon tax, as shown in Figure 68. When the carbon tax reaches C$40/tonne, government consumption will decrease by 0.11% in scenario 1. For the other two scenarios, the government consumption will decrease by 0.1% and 0.09% respectively. The differences among the three scenarios are not as significant as the differences of household consumption. But scenario 2 and scenario 3 also have better performance in this macroeconomic indicator.

For the government, its income, which includes tax revenues and transfer payments, will also decrease due to the production reduction. Conversely, the decrease of consumption will cause the production reduction from demand aspects.

It should be noted that all the economic activities are closely related. All the economic entities, including household, government, and enterprises, also have close relationship with each other. The transfer to household will benefit household for sue, but it also has some negative aspects, such as environmental benefits. Therefore, different carbon tax recycling mechanism should be considered to find out the most economic efficient option.

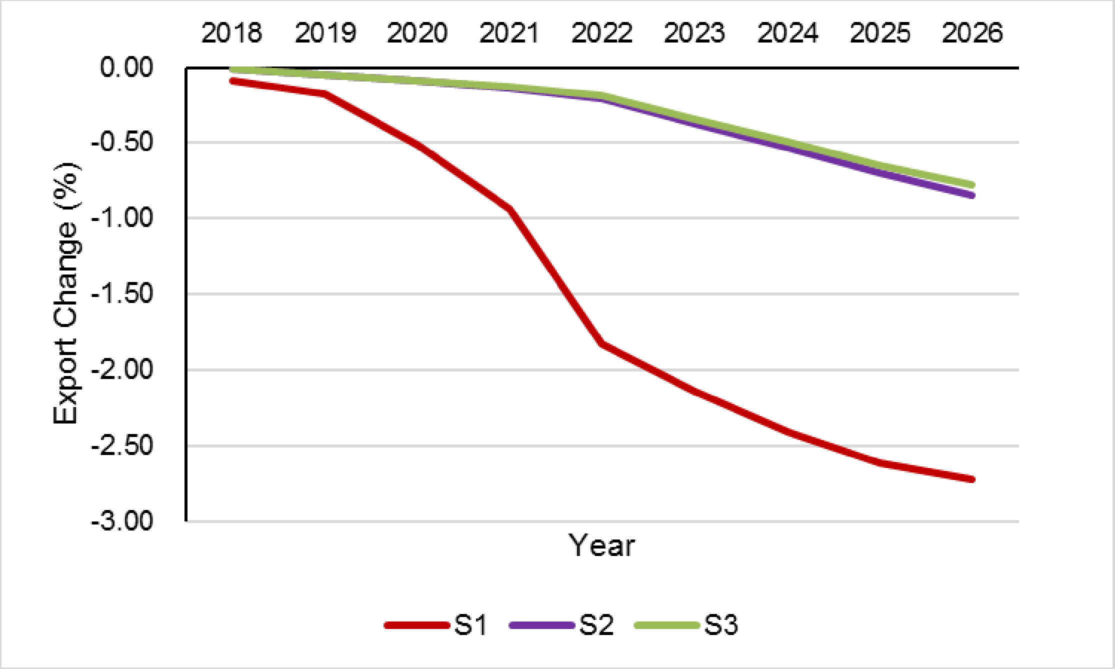


Figure 69. Export changes

For the export decrease, almost all the emission-intensive industries in Saskatchewan are mainly exported to other countries and provinces. Thus, the export will decrease due to the production decline of these industries, as shown in Figure 69. For example, Saskatchewan is the second largest net oil export provinces in Canada. After the application of carbon tax, the crude oil and petroleum products industries will be significantly affected, which will further lead to the export decrease.

When carbon tax is C$ 40/tonne, the exports will decrease by 0.9% in scenario 1. When the carbon tax rate is C$50/tonne, exports will reduce by 2.1%, which is a significant incremental reduction. In scenario 2 and scenario 3, the exports will decrease by 0.14% and 0.13% respectively. It can be seen that the export has increased in these two new scenarios, which is mainly caused by the low export in building and transportation sectors. For the emission-intensive industries, it is better to reduce the GHG emissions through technology improvements or production structure adjustment.

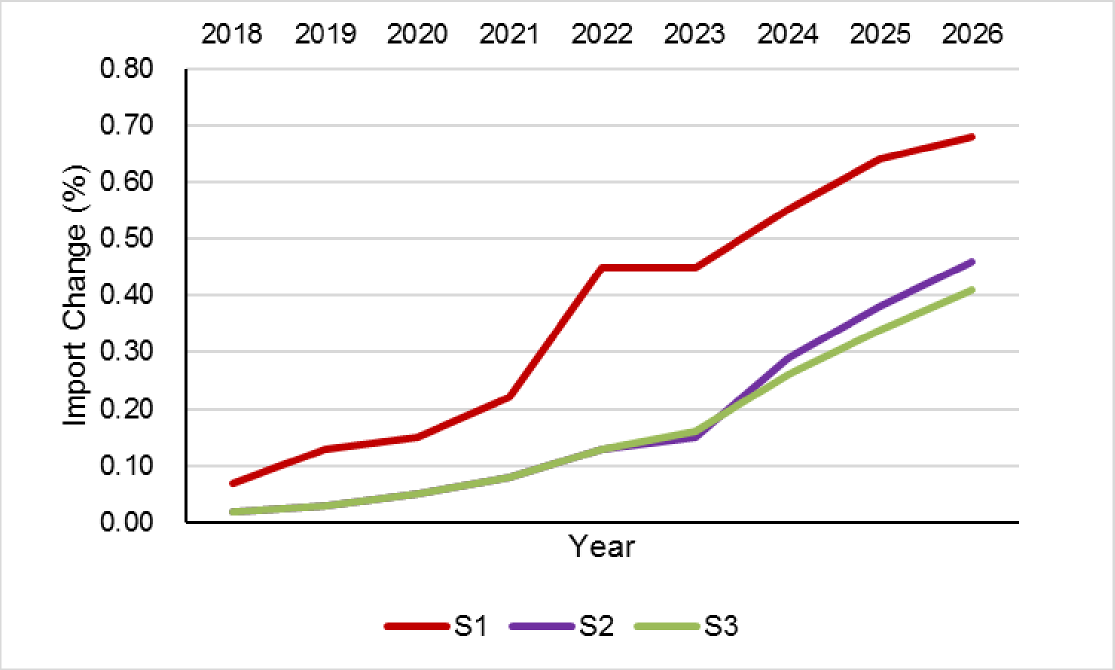


Figure 70. Import changes

For the import improvement, the tariff rate is relatively low for international import and the transportation cost is limited for inter-provincial import. The import of Saskatchewan will increase as a result, as shown in Figure 70. The impact on imports is less obvious than the impact on exports. For instance, the increase of imports is 0.22% in scenario 1 when the carbon tax rate is C$50/tonne. While, in scenario 2 and scenario 3, the increase of imports are 0.08%.

Although the domestic production will decrease, the total consumption will also decrease, which leads to a relatively low increase in imports. The import of cleaner energies will increase directly due to the carbon tax impacts. Since the production of high emission intensity industries will decrease directly, many industries will seek cleaner energies to replace them. Clean electric power and natural gas will be good alternatives for some industries. Other industries that are not closely related with energy will also be affected indirectly. This is mainly caused by the intermediate impacts of fossil fuel energies among the whole system.

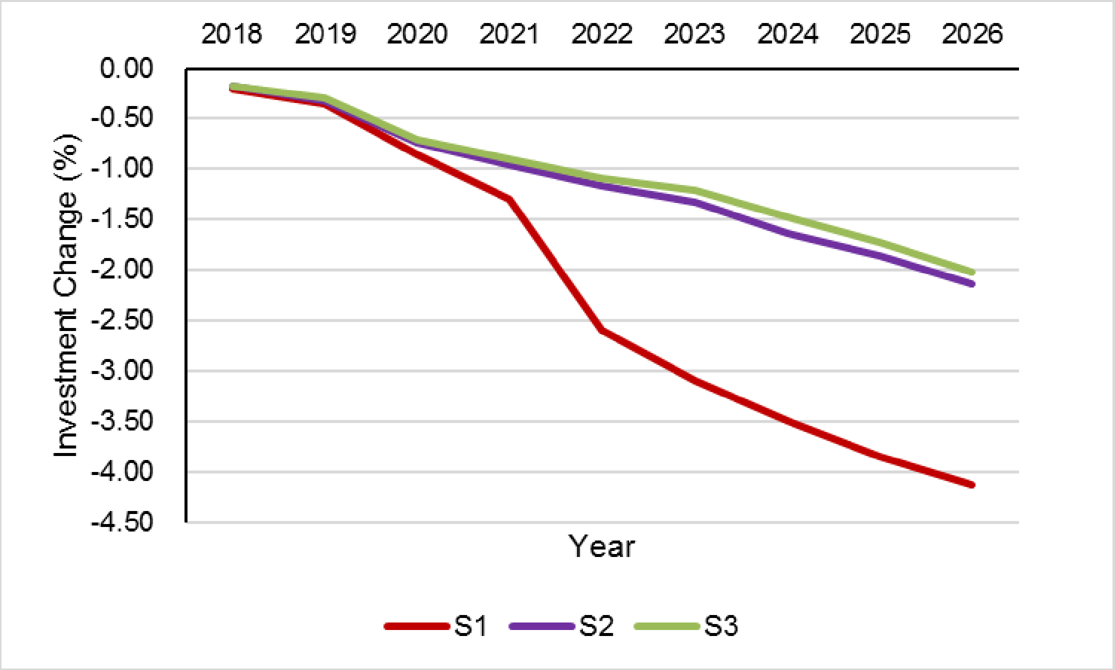


Figure 71. Investment changes

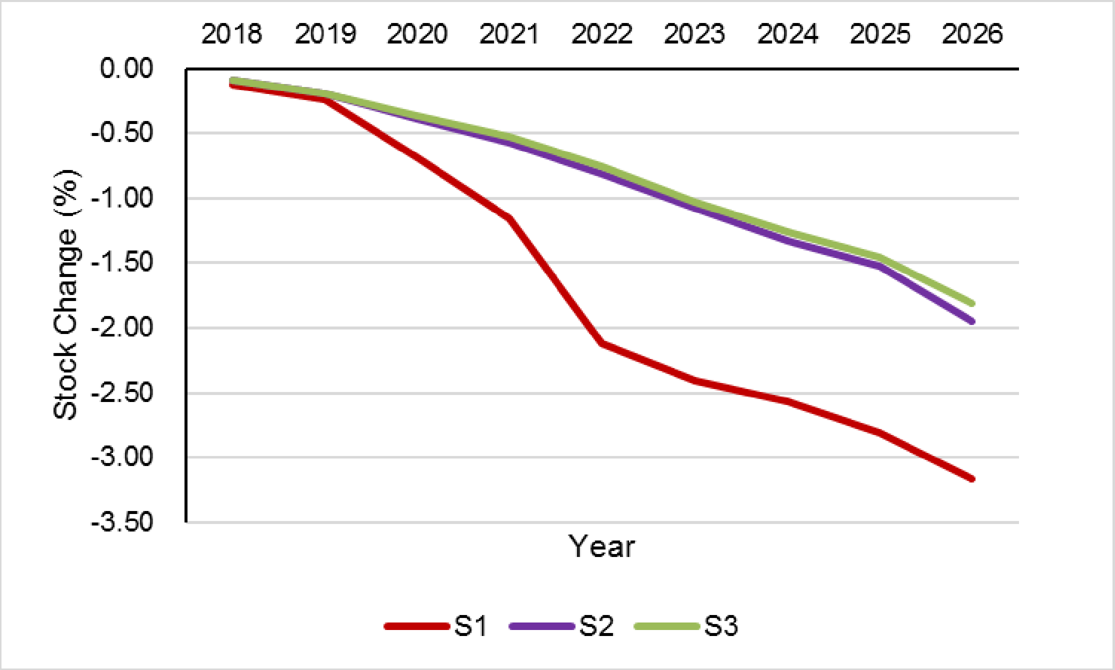


Figure 72. Stock changes

Specially, the most difference is the huge decrease of investment and stock. This is also related with the assumption in the baseline scenario. For every year, capital stock was updated via a capital accumulation equation based on an endogenous growth rate as determined by endogenous return on capital rate and endogenous total savings. This leads to the increase of investment and stock in the baseline scenario.

When comparing these three scenarios, both investment and stock will increase in scenario 2 and scenario 3, which again illustrates that the made-in-Saskatchewan climate strategy will benefit our province.

5.4. Industries overlap relationship analysis

There are compounded interactions amongst various components in the socio-economic system. The relationships among different sectors are complicated regarding to their emission performance. A total of 91 pairs of emission relationships across thirteen sectors under twenty scenarios were analyzed, as shown in Table 81 and Figure 73.

Table 81 The numbers for emission relationships of each scenario

Scenario			Emission relationships			
Numbering	Emission type	Emission source	Mutualism	Exploitation	Competition	Neutralism
a	CH_4	Gas	15	55	21	0
b	CO_2	Gas	16	59	16	0
c	N_2O	Gas	16	61	14	0
d	GHG	Gas	16	58	17	0
e	CH_4	Oil	16	63	12	0
f	CO_2	Oil	17	62	12	0
g	N_2O	Oil	21	68	2	0
h	GHG	Oil	17	62	12	0
i	CH_4	Coal	14	62	15	0
j	CO_2	Coal	14	63	14	0
k	N_2O	Coal	14	63	14	0
l	GHG	Coal	14	63	14	0
m	CH_4	Other	16	58	17	0
n	CO_2	Other	14	54	23	0
o	N_2O	Other	26	52	13	0
p	GHG	Other	18	57	16	0
q	CH_4	All	16	58	17	0
r	CO_2	All	15	67	9	0
s	N_2O	All	22	61	8	0
t	GHG	All	17	63	11	0

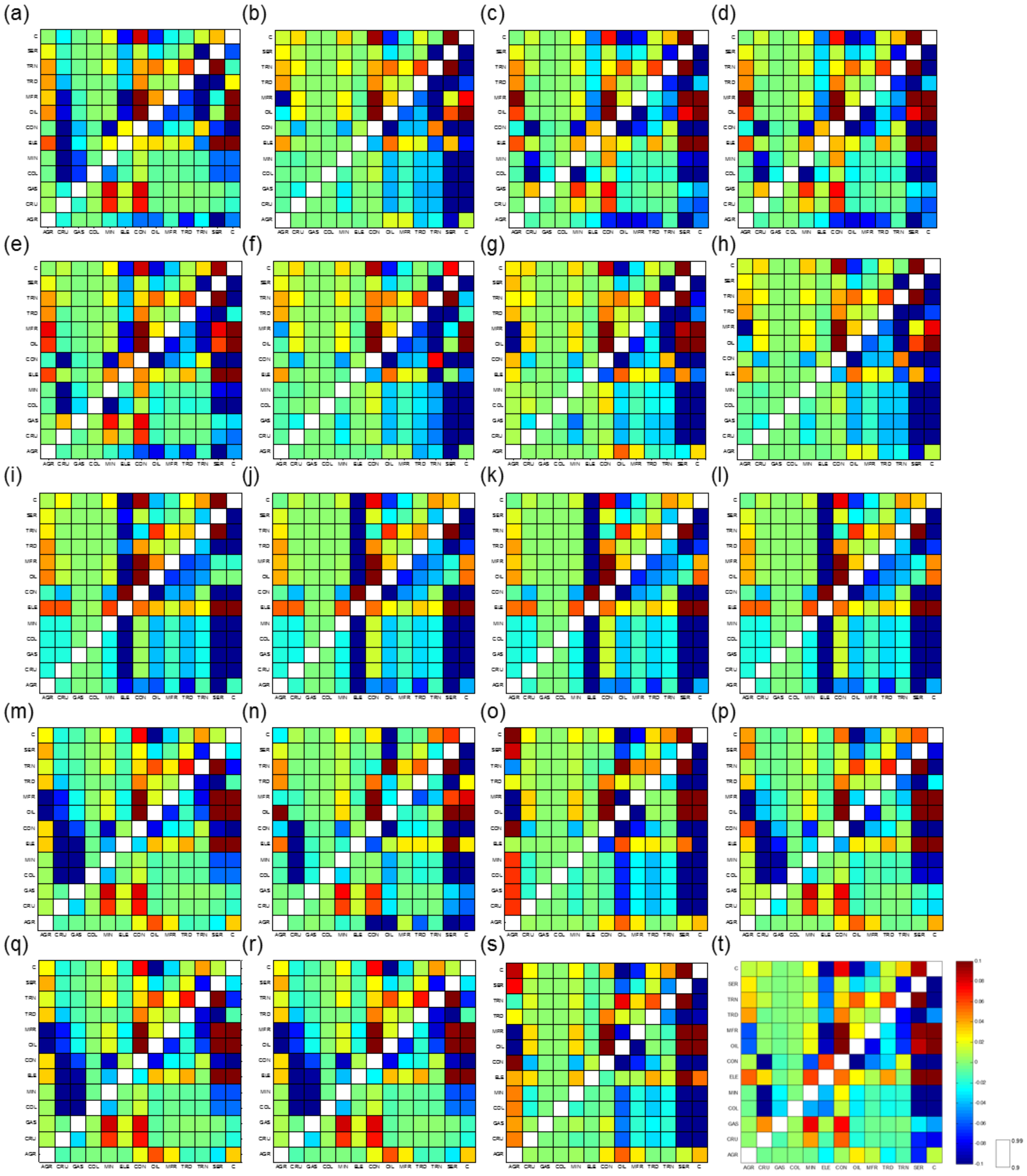


Figure 73. Emission relationships of thirteen sectors

According to Figure 73, the emission relationships of different sectors vary significantly, since the colors of different grids have large differences. The warm colors represent positive values and the cold colors represent negative values. By combining the two grids that are symmetric around the diagonal line, the emission relationship of two sectors can be determined. The color shade of one certain grid changes under different scenarios, and some even change to opposite colors in special scenarios. In a comparison of the twenty scenarios, it can be found that the emission relationships of two certain sectors will change.

Table 82 shows the numbers of four emission relationships, including mutualism, competition, exploitation, and neutralism. No neutralism relationship is observed in the table, indicating that the all sectors are strongly associated with each other. Exploitation relationships account for a large proportion of all scenarios. Competition relationships are less than 16% for most of the scenarios, and some are even lower. Mutualism relationships account for 15% to 28% of the total relationships, which indicates a need to improve the overall system.

Table 82 The emission relationships of thirteen sectors in scenario (t)

Sector	Mutualism	Exploitation	Control	Competition
AGR	3	6	2	2
MIN	1	9	1	2
COL	1	9	1	2
GAS	1	0	6	6
CRU	1	7	4	1
OIL	1	5	6	1
ELE	2	1	10	0
CON	4	9	0	0
MFR	1	4	7	1
TRN	2	2	8	1
TRD	1	4	6	2
SER	1	5	6	1
C	2	3	7	1

In ecological systems, consumers exploit producers and primary consumers are controlled by secondary consumers. By changing the system to a socio-economic system, different conclusions can be generated. Table 81 shows the emission relationships in scenario (t), which takes all GHGs and all emission sources into consideration. It can be seen that the entire system is dominated by exploitation relationships. For example, the emission relationship of AGR and MFR is (-, +), indicating that AGR obtains a net negative utility from MFR and MFR receives a positive utility from AGR. There are three sectors that controlled by most of other sectors, including ELE, TRN, and C.

In contrast, MIN, COL, CRU, and CON play an exploitative trend towards a majority of other sectors. For instance, it can be seen in the CON column of Figure 73(t) that nine grids in this column are warm colors, indicating that it controls nine sectors in the whole system. In the socio-economic system, CON and C are considered as the highest consumers. However, their emission relationships with other sectors are totally different. These results show that the emission relationships of various sectors are not all consistent with the economic structure. Also, this may differ in different jurisdictions. Thus, GHG emission reduction regulations for specific industries should be on the strength of a scientific emissions relationship analysis.

The colors of the grids in the diagonal line are all white, indicating that the internal flows in a sector always benefits itself. Besides these thirteen grids, there are only four mutualism relationships (i.e. (AGR, CON), (AGR, C), (CON, ELE) and (CON, TRN)). In a mutualism relationship, both sectors benefit from the interactive flows, which is beneficial for the entire system. The mutualism relationship is more meaningful in an emissions relationship, since it reveals effective pathways to mitigate GHG emissions. For instance, the GHG emissions of CON will decrease once the emissions of ELE are decreased due to their positively related emissions relationship. Therefore, the emissions reduction in one sector will lead to a decrease of the total GHG emissions in other sectors that have a mutualism emissions relationship with. AGR, ELE, CON and C all rank at the top for GHG emissions in Saskatchewan. Taking their close mutualism emissions relationship into consideration, it is vital to realize an emissions reduction in these four sectors.

A competition relationship means both sectors are harmed by the relationship in the traditional ecological network analysis. However, the competition relationship reflects good interactions in a GHG emissions flow analysis. According to Table 82, more than half of the competition relationships (i.e. six of eleven) happen in the GAS industry, including OIL, MFR, TRD, TRN, SER, and C. These competition relationships show that with more interactions among the above six industries with the GAS industry, the less GHG emissions will be produced. The results further illustrate that the utilization of natural gas will effectively reduce total GHG emissions. In addition, natural gas fired electricity generation makes up only thirty percent of the total generating capacity in the Province of Saskatchewan, leading to the exploitation emissions relationship of GAS and ELE. It is expected that the coal-to-gas conversion in the future will reduce GHG emissions effectively.

In the comparison of the different scenarios, evident changes for certain sectors can be found. In each column, there are significant differences among the four emission sources. For example, by comparing Figure 73(a), (e), (i), and (m), it can be seen that ELE plays different role in different scenarios. In Figure 73(i), ELE is seriously exploited by other sectors. While, in other scenarios, variations of the relationship or the degrees of the relationship can be clearly observed. It’s also worth noting that the variations in each row happen in different industries. For instance, the role of CRU varies greatly when comparing Figure 73(a), (b), and (c). CRU is exploited by other sectors in the CH_4, and N_2O emission flows, while it exploits some sectors in the CO_2 emissions network. From a systems perspective, Table 82 shows the differences of the twenty scenarios quantitively.

In scenario (o), there are twenty-seven mutualism relationships and twelve competition relationships, while there are only fifteen mutualism relationships and nine competition relationships in scenario (r).

Overall, the mutualism relationship reveals effective pathways to mitigate GHG emissions and the competition relationship reflects good interactions in the GHG emissions flows. The emissions relationships of various sectors are not all consistent with the economic structure. Thus, GHG emissions reduction regulations for specific industries should be done on the strength of a scientific emissions relationship analysis. In the Province of Saskatchewan, there is a need to improve the overall system, and vital to realize emissions reduction in AGR, ELE, CON and C. The coal-to-gas conversion in the future is expected to reduce the GHG emissions effectively.

6. Summary

6.1 Affordable penalty analysis

Table 83 The penalty and benefit rate of different companies

Company	Percentage	
	Lower bound	Upper bound
Mosaic	8%	18%
Agrium Inc.	8%	18%
PotashCorp	2%	12%
Prairie Mines & Royalty Ltd	17%	27%
CCRL	20%	30%
Yara Belle	10%	20%
Evraz	7%	17%
Terra Grain Fuels Inc.	31%	41%
Meadow Lake Mechanical Pulp Inc.	10%	20%
TransGas	79%	89%

Note: The penalty is calculated by carbon tax rate equals to 50 C$/tonne.

6.2 Real Reduction ability

Table 84 Real reduction ability of different industries

	Rate of mitigation	
Industry	**Lower bound**	**Upper bound**
Mining-Coal	70%	85%
Mining-Potash	54%	64%
Petroleum Refinery	57%	77%
Manufacturing-fertilizer	12%	95%
Manufacturing-steel	50%	99%
Manufacturing-ethanol	30%	46%
Manufacturing-pulp	34%	51%
Trans-pipeline	10%	15%

6.3 Carbon tax impacts analysis

Table 85 GDP change under different scenarios

	GDP Change (%)								
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
S1	-0.12	-0.24	-0.69	-1.16	-2.12	-2.41	-2.57	-2.81	-3.16
S2	-0.09	-0.20	-0.39	-0.57	-0.81	-1.08	-1.33	-1.52	-1.95
S3	-0.09	-0.20	-0.37	-0.53	-0.76	-1.03	-1.26	-1.45	-1.81

Appendix

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Appendix Y: Westmorel and Coal Company Form 10K 2016

Appendix Z: Westmorel and Coal Company Annual Report