Candor Engineering Ltd.

Project Report

COSIA SAGD Reference Facilities

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List of Abbreviations

Abbreviations	**Full Name**
API	American Petroleum Institute
bbl	Barrel
BFD	Block Flow Diagram
BFW	Boiler Feed Water
BPSD	Barrel per Stream Day
BS&W	Basic Sediment and Water
CCR	Conradson Carbon Residue
COSIA	Canada’s Oil Sands Innovation Alliance
cP	Centipoise
CPF	Central Processing Facility
CSS	Cyclic Steam Stimulation
CWE	Cold Water Equivalent
d	Day
DB	Duct Burning
dilbit	Diluted Bitumen
EFD	Energy Flow Diagram
ESP	Electrical Submersible Pump
ETAP	Environmental Technology Assessment Portal
Evap	Evaporator
FADB	Forced Air Duct Burning
FWKO	Free Water Knock Out
GHG	Greenhouse Gas
GL	Gas Lift
GT	Gas Turbine
HHV	Higher Heating Value
HP	High Pressure
HRSG	Heat Recovery Steam Generator
h	Hour
IBP	Initial Boiling Point
IGF	Induced Gas Floatation
ISF	Induced Static Floatation

l	Litre
LP	Low Pressure
LPG	Liquid Petroleum Gases
M&HB	Material and Heat Balance
ML	Mechanical Lift
mol	molar
MPa	Mega Pascal
MW	Mega Watt
MWh	Mega Watt hour
NO_x	Nitrogen Oxides
ORF	Oil Recovery Filter
OTSG	Once Through Steam Generator
PFD	Process Flow Diagram (used interchangeably in this report with BFD)
PFV	Pre-Flash Vessel
SAGD	Steam Assisted Gravity Drainage
SGER	Specified Gas Emitters Regulation
SOR	Steam to Oil Ratio
STP	Standard Temperature and Pressure
t	Tonne or Metric Ton
TBP	True Boiling Point
TDS	Total Dissolved Solids
TOC	Total Organic Carbon
VRU	Vapour Recovery Unit
WAC	Weak Acid Cation Exchanger
WLS	Warm Lime Softening
wt	Weight

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1. Introduction

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1.2. Scope of Report

COSIA has asked Candor Engineering (Candor) to complete this report to provide overviews of, and context for, six Steam Assisted Gravity Drainage (SAGD) reference Central Processing Facilities (CPFs). These reference CPFs (see Appendices 1 to 6) were prepared by JACOBS Consultancy (Jacobs) for COSIA and are depicted only as process flow diagrams (PFD) and energy flow diagrams (EFD).

This document provides context for these CPFs containing descriptions of:

(1) COSIA's motivation for constructing SAGD reference CPFs (see Section 1.3 below),

(2) Description of how bitumen is extracted from *in situ* oil sands operations (see Section 2), and

(3) SAGD process and energy flow and interconnectivity for each of the six reference CPFs (see Sections 5 to 9).

1.3. Purpose of the Report

COSIA will use of this document to:

- Help technology vendors to become more familiar with SAGD operations, including the material and energy balances for various reference configurations in the respective CPFs,
- Inspire and stimulate creative new ideas to enhance the efficiency of, while reducing the environmental footprint associated with, SAGD production technologies, including GHG emissions and water use, and
- Support technology vendors to:
  - Identify how their technologies might integrate with existing SAGD facilities,
  - Assist them in quantifying the potential GHG and water benefits of their technology, and
  - Better present their proposals to COSIA.

Technology Vendors are encouraged to submit non-confidential information about their technology to COSIA through its Environmental Technology Assessment Portal (ETAP) at http://www.cosia.ca/etap?page=etap.

2. Oil Sands Overview

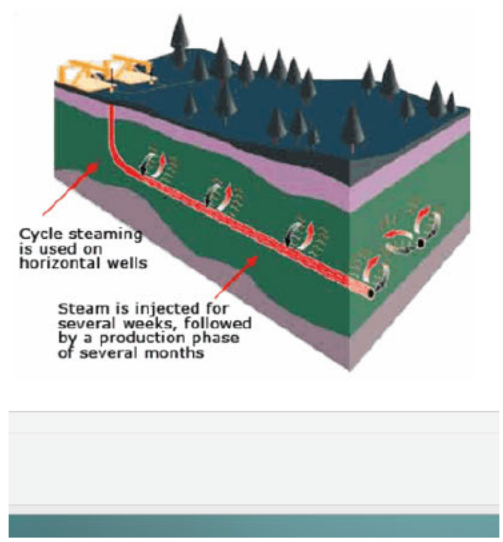
2.1. Location of deposits

Oil sands deposits underlie about 142,000 square kilometers of Alberta, which represents approximately 20% of Alberta's land area.[1] There are three areas where oil sands deposits are found - the Athabasca, Peace River, and Cold Lake. The Athabasca oil sands area, which surrounds Fort McMurray, has the largest reserves and contains all operating surface mining projects and the majority of *in situ* projects. There are also large *in situ* projects in the Cold Lake and Peace River areas. See Figure 1 for maps of oil sands deposits in Alberta.

Figure 1: Alberta Oil Sands Deposits.

2.2. *In Situ* Recovery Technologies

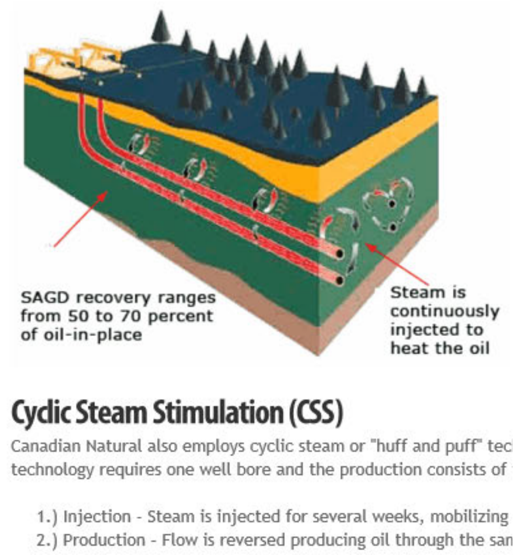
Of the recoverable oil sands reserves, 80 per cent are buried too deep for open pit mining and can only be accessed through *in situ* processes.[2] Currently two *in situ* processes are used for commercial production of oil sands crude or bitumen from underground reservoirs: Cyclic Steam Stimulation (CSS) and Steam Assisted Gravity Drainage (SAGD). In both cases, high pressure (HP) steam is injected into the ground to heat up and reduce the viscosity of bitumen from about 1 million centipoise (cP) to 10 cP so that the hot bitumen can flow into production wells.[3]



CSS is the older of the two thermal *in situ* processes and is deployed only in the Cold Lake area. To access the reservoir, CSS originally deployed vertical wells, but more recently horizontal wells have been used. HP steam is injected into the reservoir for a period of time (see Figure 2) to heat the bitumen, and then stream injection is stopped to allow the hot bitumen to flow back to the same wells. The bitumen is then pumped to the surface (also known as lifting). The cycle of injection-heating-production is repeated until the reserves around the wells are depleted.

Unlike CSS, the SAGD process is continuous and was first piloted in the Foster Creek area in 2000 (see Figure 3). In commercial SAGD, several pairs of horizontal wells are drilled from a single well pad into the reservoir. The two wells in each pair in the horizontal section are separated vertically by 4 to 6 m. HP steam is injected into the top well (called the Injector) and the steam rises to form a steam chamber above each injector, heating the bitumen to about 200 °C and reducing its viscosity to about 10 cP so that it will flow within the reservoir. Together with the steam condensate and reservoir connate water, a mixture of bitumen and water (called an emulsion) drains by gravity into the lower well of the well pair (called the Producer).

The emulsion is pumped to the surface by either gas lift (GL) or mechanical lift (ML). GL involves injecting high-pressure gas into the Producer to supplement formation gas, and to use its pressure to lift the emulsion to the surface. With GL, the SAGD operator must maintain the reservoir at relatively high pressure increasing the possibility of heat loss to non-bitumen bearing zones, and contributing to a less than optimal Stream to Oil ratio (SOR), according to COSIA.(5)



ML in SAGD typically deploys electrical submersible pumps (ESPs), capable of handling high temperatures, to lift the emulsion to the surface. This technology can reduce SAGD operating pressure, steam losses and energy usage, which may improve (i.e., reduce) the overall SOR, also according to COSIA.(5) ESPs are increasingly being used by the SAGD industry.

With the exception of one current CSS producer, who continues to expand production using CSS, virtually all new or expanded thermal *in situ* projects use the SAGD technology for bitumen extraction. SAGD is currently the standard thermal *in situ* production technology.(6 & 7)

2.3. Overview of SAGD Central Processing Facilities

The CPF of SAGD operations takes in the water-oil emulsion from the Producer wells and outputs pipeline quality diluted bitumen (dilbit) and high pressure steam to maintain bitumen production. As shown in Figure 4, there are a number of other streams of material and energy flows entering and leaving the CPF.

Streams entering the CPF include: produced emulsion which is a mixture of bitumen, steam condensate and reservoir connate water, natural gas for fuel, electricity from the Alberta grid (Grid), make-up saline water, diluent, air for combustion and various consumable or chemicals. Streams exiting the CPF include: dilbit, high pressure steam for SAGD injection, electricity export to the Grid, flue gas exhausts from boilers and heaters, liquid blow down from steam separators and solid wastes from water or bitumen treatments.

Within the CPF, there are three major processes: oil-water separation, water treatment and steam generation (Figure 4):

a. **Oil-water (Emulsion) Separation and oil treatment:** In this process, bitumen is liberated from the emulsion in two stages. The first is by free water knock-out (FWKO) and the second by oil treatment. The oil treatment stage involves the addition of diluent (a light hydrocarbon needed in the pipeline delivery of bitumen to markets) to decrease the density of diluted bitumen, and the addition of chemicals to break the emulsion.

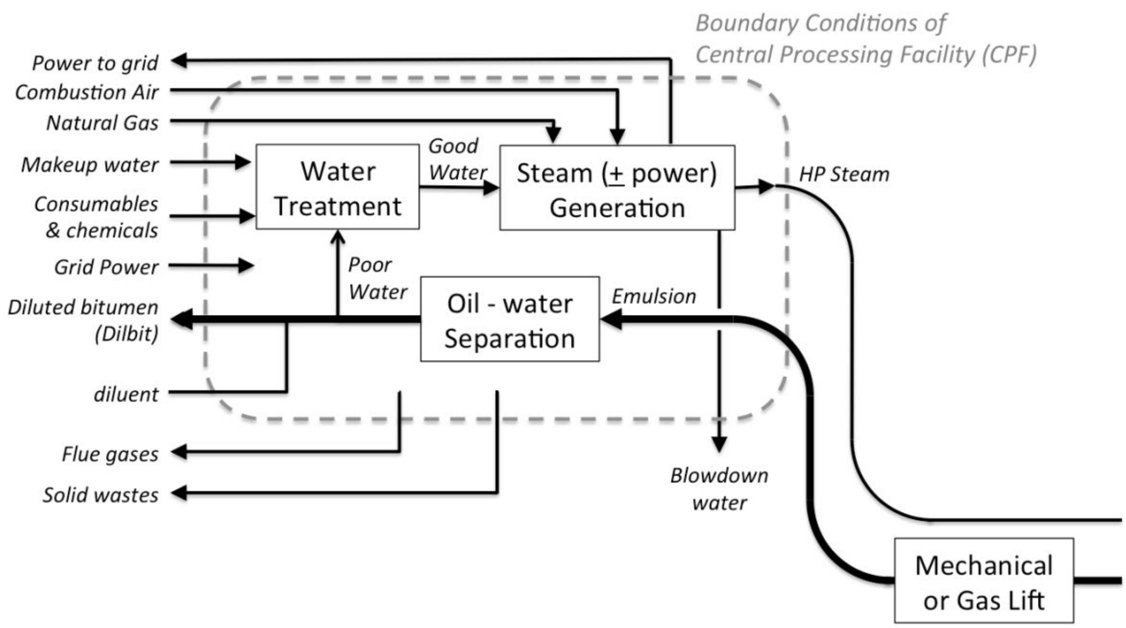


Figure 4: The inputs, outputs and key processes that are part of Central Processing Facilities (CPF) in SAGD operations. The dotted line shows the boundary conditions for the CPF.

b. **Water Treatment**. The produced water, after separation from the bitumen, is cleaned in three successive stages to remove its hardness and silica so that it can achieve the quality needed for steam generation in conventional boilers. In conventional SAGD CPF, these three stages are typically (i) warm lime softening (WLS), (ii) filtration, and (iii) weak acid cation exchanger (WAC).

c. **Steam Generation (without or with power cogeneration).** Water of a high enough quality to be boiler feed water (BFW) is provided to either a once-through steam generator (OTSG) or a heat recovery steam generator (HRSG) to produce wet steam that is then passed through a HP steam separator where 100% HP steam of about 9.9 MPa will be produced and delivered to the SAGD injector wells. The liquid coming from the separator is sent to deep wells for disposal. The steam generation stage may also include power generation to meet both the needs for the CPF and to provide power to the electrical grid. Typically, this is done using a gas turbine that consumes natural gas and produces both electricity and a hot air that enters a HRSG for steam recovery.

3. Synopses of the Six SAGD Reference CPFs

Sections 5 to 10 of this report contain overviews of six different SAGD reference Central Processing Facilities (CPFs), each with their own Process Flow Diagram (PFD) and Energy Flow Diagram (EFD). This section introduces the six CPFs and identifies the exclusions and limitations in this analysis.

3.1. CPF Summary

The six CFPs are as follows:

CPF#1 (ML-WLS-OTSG): This Base case, as described in Section 5, deploys:

- Electric Submersible Pump (ESP) as the mechanical lift (ML) technology to produce the emulsion from the reservoir;
- Warm Lime Softening (WLS) for water treatment;
- Once-through Steam Generation (OTSG) to provide the steam requirements, and
- Power is imported from the Grid.

CPF#2 (ML-Evap-OTSG): Similar to CPF#1, but:

- An evaporator replaces WLS for water treatment to produce a much higher quality boiler feed water (BFW). Section 6 will provide further description of Evaporators. As a result, higher quality steam could be produced in the OTSG, eliminating almost all the blow down and its deep well disposal.

CPF#3 (GL-WLS-OTSG): Similar to CPF#1, but:

- Gas lift (GL) technology using pipeline HP natural gas replaces ESPs to produce the emulsion from the reservoir. This process not only produces the emulsion to the surface, but also depressurizes the pipeline natural gas to meet the OTSG burner pressure requirement. Section 7 contains further details of the GL technology.

CPF#4 (ML-WLS-OTSG-Cogen): Similar to CPF#1, but:

- Cogeneration using a combination of gas turbine (GT) and heat recovery steam generator (HRSG) are used to eliminate power import and augment steam generation from the OTSG. The electricity output will be used on site and any excess is exported to the Grid. Further details can be found in Section 8, including how the OTSG and the new HRSG are integrated to supply the same steam requirement.

CPF#5 (ML-Evap-OTSG-Cogen): Similar to CPF#4, but:

- An evaporator, as was described in CPF#2, replaces WLS for water treatment to produce a much higher quality boiler feed water (BFW). Section 9 has more details.

CPF#6 (ML-WLS-Cogen): Similar to CPF#1, but:

- Full cogeneration of HP steam from HRSG and electricity from GT will be implemented instead of OTSG and power import. Water treatment is still accomplished with WLS. More details are contained in Section 10.

3.2. Exclusions to CPF Descriptions

The following are excluded from the work presented here:

- Reservoir characteristics, performance or properties other than those in the PFD;
- Engineering design, material, construction or performance of the horizontal wells and their pads;
- SAGD operation and performance external to the CPF with the exception of emulsion pumping;
- Blending of the treated SAGD crude for pipeline delivery to refineries other than those in the PFD;
- Design, material, construction and operation of the emulsion collection and delivery systems to CPF;
- Design, material, construction and operation of the CPF and steam distribution system including its mechanical and civil support system, steam condensate handling and thermal insulation from the steam generators to the well heads of each pad;
- Design, material, construction and operations of any and all electricity transforming, distribution and connection systems;
- Environmental monitoring systems;
- CPF process control;
- Operation and maintenance (O&M) including personnel;
- Any and all cost data;
- Any and all SAGD management or company information;

3.3. Limits to CPF Descriptions

Candor is not privy to the Jacobs' methods or assumptions used to complete these SAGD reference CPFs, or to the private communication between COSIA and Jacobs in respect of authorizing, reviewing or approving its work.

Consequently, Candor can only use the information shown in the PFD, utilities and EFD. In providing overview and context, Candor will use publicly available information only.

This report does not include:

- Validation of Jacobs' work, including but not limited to, its accuracy of calculation, design, estimate, data package, engineering or mathematic software, PFD or mass and heat balances (M&HB), or its technical capability.
- Any information not available in the public domain;
- Validation of any information whether public or proprietary provided by COSIA;
- Provide additional calculations, flow sheets or diagrams than those provided by Jacobs, unless specifically requested by COSIA and agreed to by the authors;
- Any vendor specific process or unit in respect of its design, material, construction or operation;
- Description of any chemical or consumables, energy and its compositions, process streams and their compositions as shown or absent in the PFD or M&HB;
- Validations of any equilibrium state or resultant compositions of any streams and their respective states as shown or absent in the PFD or M&HB;

- Validation any chemical reactions, their respective reactants or products, their equilibrium products, or their reaction kinetics as shown or absent in the PFD or M&HB;
- Validation of Jacobs' numerical simulations; and
- Comparison or comments in respect of the economics of any and all the cases

4. Methodology, Assumptions, and Summaries of Results

4.1. Methodology ad Assumptions

Jacobs in preparing the PFD, utility and EFD had used a number of assumptions in carrying out their calculations. These included bitumen properties (Table 1), diluent properties (Table 2) and natural gas composition (Table 3).

Using data from the Base Case PFD and EFD, Candor has estimated the GHG intensity of the natural gas to be 51.9 kg CO_2 per GJ (HHV). For further details, please consult COSIA.

Table 1: Bitumen Properties.

Variable	Units	Value
IBP	°C	242
T 5%	°C	337
T 10%	°C	354
T 30%	°C	456
T 50%	°C	567
Standard Density	kg/m^3	1019
Sulphur	%	5.05
CCR	%	15
API		8.4

Table 2: Diluent Properties

Variable	Units	Value
TBP 0%	°C	-2
TBP 5%	°C	76
TBP 10%	°C	91
TBP 30%	°C	109
TBP 50%	°C	127
TBP 70%	°C	146
TBP 90%	°C	200
TBP 95%	°C	240
Liquid Mass Density (at STP)	kg/m^3	765
API		53.5

Table 3: Natural Gas Composition

Component	Mol %
Methane	95.1%
Ethane	1.8%
Propane	0.6%
i-Butane	0.3%
n-Butane	0.0%
i-Pentane	0.1%
CO_2	0.8%
Oxygen	0.0%
Nitrogen	1.4%
Ammonia	0.0%
H_2S	0.0%

Drawing on these assumptions, Jacobs used common engineering software, proprietary correlations, and their experience in designing facilities to generate the PFDs, material balances and EFDs for the six CPFs that are described in this document.

Standard engineering rules were used to generate equipment sizes. Heater efficiencies were derived from unit heat balances and combustion modeling.

4.2. Summary of the Six Cases

A summary of all the cases including their respective energy requirements and key performance indicators is reproduced below in Table 4. Note that each of the six cases produces 5,247 m^3 (or 33,000 barrels) per day of bitumen at a steam to oil ratio (SOR) of 3 on a cold-water equivalent (CWE) basis.

Table 4: Summary of All 6 Cases.

		Benchmark Study Data Average	Template Base Case: ML - WLS - OTSG	Template Case 2: ML - Evap - OTSG	Template Case 3: GL - WLS -OTSG	Template Case 4: ML-WLS-OTSG-Cogen	Template Case 5: ML - Evap - Cogen	Template Case 6: ML-WLS-Cogen
Bitumen Rate	m^3/day	7,407	5,247	5,247	5,247	5,247	5,247	5,247
Dilbit Product	m^3/day		8,258	8,258	8,258	8,258	8,258	8,258
SOR		3.1	3.0	3.0	3.0	3.0	3.00	3.00
Product Steam Quality			77%	90%	77%	77%	90%	77%
Emulsion Temp	°C	158.9	175.3	175.3	163.8	175.3	175.3	175.3
BFW Temp	°C	151.7	170.0	163.3	150.0	170.0	163.2	170.0
Stack Temp	°C	177.0	195.0	188.3	174.9	195.0	188.0	195.0
OTSG Efficiency	% HHV		83.2	83.2	83.1	83.2	83.5	N/A
Total Natural Gas Demand	MMSCFD		38.1	36.5	40.7	43.8	42.2	49.5
OTSG/HRSG Fired Duty (HHV) (8)	MMBtu/hr		1,728	1,657	1,817	1,477	1,371	1,185
Direct CO2 Emissions (OTSG, HRSG & Glycol Heater)	MT/day		2,191	2,104	2,291	2,519	2,419	2,830
Power Consumption	MW		17.9	33.9	15.3	16.6	32.6	13.9
Power Export	MW		-	-	-	26	10.4	74.1
Indirect CO2 Emissions (3)	MT/day		328	621.1	281	-483	-190	-1356
Total CO2 Emissions	MT/day		2,519	2,725	2,572	2,037	2,229	1,473
Stack loss per m3 of bitumen (HHV)	GJ/m3	1.38	1.17	1.12	1.23	1.71	2.01	1.98
Glycol System loss per m3 of bitumen	GJ/m3	0.77	0.57	0.58	0.95	0.61	0.60	0.67
Electricity Loss/m3 of bitumen (2)	GJ/m3	0.22	0.54	1.02	0.46	0.50	0.98	0.42
Fuel Consumption per m3 of bitumen (HHV)	GJ/m3	8.32	8.44	8.60	8.94	8.90	8.58	10.38
GHG kg per m3 of bitumen (1)	kg/m3	478.4	480.1	519.5	490.1	388.2	424.9	280.8
Stack loss per GJ of Steam (HHV)	GJ/GJ	0.17	0.14	0.14	0.15	0.21	0.25	0.24
Glycol System loss per GJ of Steam	GJ/GJ	0.10	0.07	0.07	0.12	0.07	0.07	0.08
Electricity Loss/GJ of Steam (2)	GJ/GJ	0.03	0.07	0.12	0.06	0.06	0.12	0.05
Fuel Consumption per GJ of steam (HHV) (4)	GJ/GJ	1.01	1.05	1.07	1.09	1.13	1.09	1.27
GHG kg per GJ of steam (1)	kg/GJ	58.2	58.8	63.6	60.1	47.6	52.1	34.4

1) GHG for Template cases only includes CO2 equiv. for combustion and electrical imports CO2 eqiv (no flare or volatile emissions) 2014-12-18
2) Benchmark data includes CPF power usage only while Template data includes Well pad power
3) Includes credit for exporting power at grid emissivity
4) Fuel Consumption includes natural gas, produced gas and imported power.
5) Steam energy (GJ of Steam) is specifed based on the steam enthalpy of 2723 KJ/kg
6) Case 4 and 5 are designed with a small turbine (GE 6B) for internal demands and some export. Duct burning is specified based on keeping 4 OTSG's at full capacity.
7) Case 6 is specified with a large turbine (GE 7E) with duct burning adjusted to meet SAGD steam demand.
8) OTSG/HRSG Duty includes OTSG fired duty plus HRSG duct burning duty. Glycol heater and Gas Turbine duties are not included.

Table 5: Comparison of Specific Energy, Water and GHG Intensity of all 6 Cases.

	Unit	Base Case	Case 2	Case 3	Case 4	Case 5	Case 6
Key Process Units (Red indicates change from the Base Case)		ML-WLS-OTSG	ML-Evap-OTSG	GL-WLS-OTSG	ML-WLS-OTSG-Cogen	ML-Evap-OTSG-Cogen	ML-WLS-Cogen
Key Performance Indicator							
Fuel Consumption per m^3 of Bitumen (HHV)	GJ/m^3	8.44	8.60	8.94	8.90	8.58	10.38
Relative to Base Case		100%	102%	106%	105%	102%	123%
Water Consumption per m^3 of Bitumen	m^3/m^3	0.68	0.52	0.72	0.68	0.52	0.68
Relative to Base Case		100%	76%	106%	100%	76%	100%
Electricity Consumption per m^3 of Bitumen	MWh/m^3	0.30	0.56	0.25	0.27	0.54	0.23
Relative to Base Case		100%	189%	86%	93%	182%	78%
Direct GHG Intensity	kg/m^3	418	401	437	480	461	539
Indirect GHG Intensity	kg/m^3	63	118	54	-92	-36	-259
Net GHG Intensity	kg/m^3	480	519	490	388	425	281
Relative to Base Case		100%	108%	102%	81%	89%	58%

Table 5 lists the comparisons of the ley performance indicators for the six cases in terms of water conservation, energy efficiency gains and GHG emissions reduction.

The comparisons provide the following observations:

- Replacing WLS with Evaporators would achieve the best water conservation performance, reducing water consumption by 24% in Cases 2 and 5.
- However, the improved water conservation using Evaporators would be accomplished at the cost of higher fuel or electricity intensity. The fuel intensity would increase by a modest amount of 2%. On the other hand, electricity intensity is increased significantly by 89 or 82% respectively for Cases 2 or 5.
- Supplementing OTSG and eliminating power import by adding a 43 MW cogeneration into SAGD would increase fuel consumption by 2 or 5% depending on whether water treatment is achieved by Evaporators or WLS.
- With cogeneration addition, electricity intensity would be reduced by 7% if WLS is used for water treatment, but escalated by 82% if Evaporators are used instead.
- In Case 6, the replacement of OTSG and elimination of import power, while maintaining WLS for water treatment, with an 88 MW cogeneration plant, would consume 23% more fuel per unit of production.
- All cogeneration cases export excess power to the Grid: the export would be 10 MW or 26 MW if Evaporators or WLS is used to treat water, while full cogeneration in Case 6 would export 74 MW of excess power.
- In all three cogeneration cases, excess power export to the more GHG intensive Grid would earn offset credits which could be used to reduce SAGD GHG intensity. The GHG reductions through

displacing existing higher GHG intensity grid power result in emission intensities reductions of 92, 36 or 259 kg/m^3 respectively for Cases 4, 5 or 6 as shown in Table 5. More details in respect of the credit calculations will be found in the appropriate sections.

- In Cases 4 and 5 when cogeneration is added to partially replace the OTSGs, the GHG intensity reduction is 11% or 19% respectively depending on whether Evaporators or WLS is used for water treatment. The best GHG intensity reduction of 42% is achieved when full cogeneration is implemented and WLS is kept for water treatment as shown in Case 6.
- Gas Lift would reduce electricity consummation by 14% but increase the fuel or water intensities by 6%, and GHG intensity by 2%.

Table 6 shows the respective BFW temperature, flue gas compositions and blow down compositions of the 6 cases:

Table 6: Key Parameters of All 6 Cases

	Unit	Base Case	Case 2	Case 3	Case 4	Case 5	Case 6
Key Process Units (Red indicates change from the Base Case)		ML-WLS-OTSG	ML-Evap-OTSG	GL-WLS-OTSG	ML-WLS-OTSG-Cogen	ML-Evap-OTSG-Cogen	ML-WLS-Cogen
Boiler Feed Water Flow Rate	kg/h	851,624	727,950	851,809	851,661	728,068	851,624
Boiler Feed Wate Quality							
Total Dissolved Solids	mg/l	6,059	11	6,256	6,059	11	6,059
Silica	mg/l	34	0	34	34	0	34
Hardness	mg/l	0	1	0	0	1	0
Total Organic Carbon	mg/l	515	0	514	515	0	515
Flue Gas Flow Rate	MMCFD	462	443	491	369	369	769
Flue Gas Temperature	°C	195	188	175	195	188	195
Flue Gas Component Flow Rates							
Cabon dioxide	t/day	2,191	2,104	2,291	2,519	984	2,786
Sulphur dioxide	t/day	0.06	0.06	0.06	0.06	0.00	0.00
Nitrogen oxides	t/day	0.4	0.4	0.4	3.2	2.8	3.7
Oxygen Content in Flue Gas	%	2.1%	NA	NA	6.8%	11.4%	7.2%
Blow Down Flow Rate	kg/h	63,435	0	59,141	63,454	0	63,442
Blow Down Solids Content	mg/l	28,472	0	31,537	28,464	0	28,467
Blow Down Solid Flow Rate	kg/h	2,153	0	2,217	2,153	0	2,152

5. Central Processing Facility #1 (ML-WLS-OTSG)

The Process Flow Diagram (PFD) and Energy Flow Diagram (EFD) for this CPF#1 are provided in Figures 5 and 6, respectively. The following description will focus on the key technologies in each of the three processes in SAGD CPFs. They will not be encumbered by repeating the quantities and compositions of the flow streams which are available on the PFD or EFD.

5.1. Mechanical lift (ML)

Mechanical Lift (ML) using Electric Submersible Pumps (ESPs) (not shown in the PFD of Figure 5) is employed by the majority of commercial SAGD projects to produce bitumen-water emulsion from the reservoir to the surface. ESPs are a type of progressive cavity pumps driven by electricity sent by cables from the surface to the ESP motors located at the bottom of the Producers.(8) They pump the emulsion from each Producer to the surface of each pad. The emulsions from all the pads are then aggregated into a single pipeline and delivered to the CPF for oil-water separation and oil treatment.

5.2. Oil-Water Separation

The grey box at the top of Figure 5 summarizes the emulsion treatment to separate bitumen from the produced emulsion. It starts with pressure let down in the pre-flash vessel (PFV) to release dissolved gases from the emulsion. The de-gassed emulsion then flows to the free water knock-out (FWKO) vessel where un-emulsified water is separated with the aid of added chemicals to break down the emulsion and diluent. The purpose of the diluent is to form diluted bitumen (dilbit) that has a lower density in order to facilitate its separation from water by gravity.

The remaining emulsion is cooled from 175 to 133 ^{o}C by on-spec boiler feed water (BFW) and then flows to oil treaters where more chemicals are added. Cleaned dilbit is produced in the oil treaters and flows to a vapour recovery unit (VRU). In the VRU, liquid petroleum gases (LPGs) are separated from the clean dilbit to comply with pipeline vapour pressure limits. The recovered LPGs from the PFV and VRU are combined and used to supplement the total natural gas requirement for steam generation in the OTSG.

5.3. Water Treatment

The produced water separated from the oil is then treated to meet BFW quality for steam generation. The process is represented in the two boxes below the oil treatment box. The first step is to remove the residual bitumen in the recovered produced water from the FWKO and oil treaters. This is accomplished in a skim tank and then by induced gas floatation (IGF), induced static floatation (ISF) or oil recovery filters (ORF).(9) IGF or ISF separates oil from water by injecting small gas bubbles to attract the hydrophobic oil droplets and lift them to the water surface where the oil will be skimmed off. The recovered wet oil from IGF or ISF is sent to FWKO inlet stream while the de-oiled produced water will be treated in successive steps to meet BFW specification.

The goal of water treatment is to remove all the hardness and some silica from the produced water as well as from the make-up saline water such that the best quality steam could be produced subject to the remaining hardness and silica contents. Some hardness in the make-up saline water is first removed by ion exchangers and then added to the clean produced water for removal of the remaining hardness and some silica in the WLS process.(10)

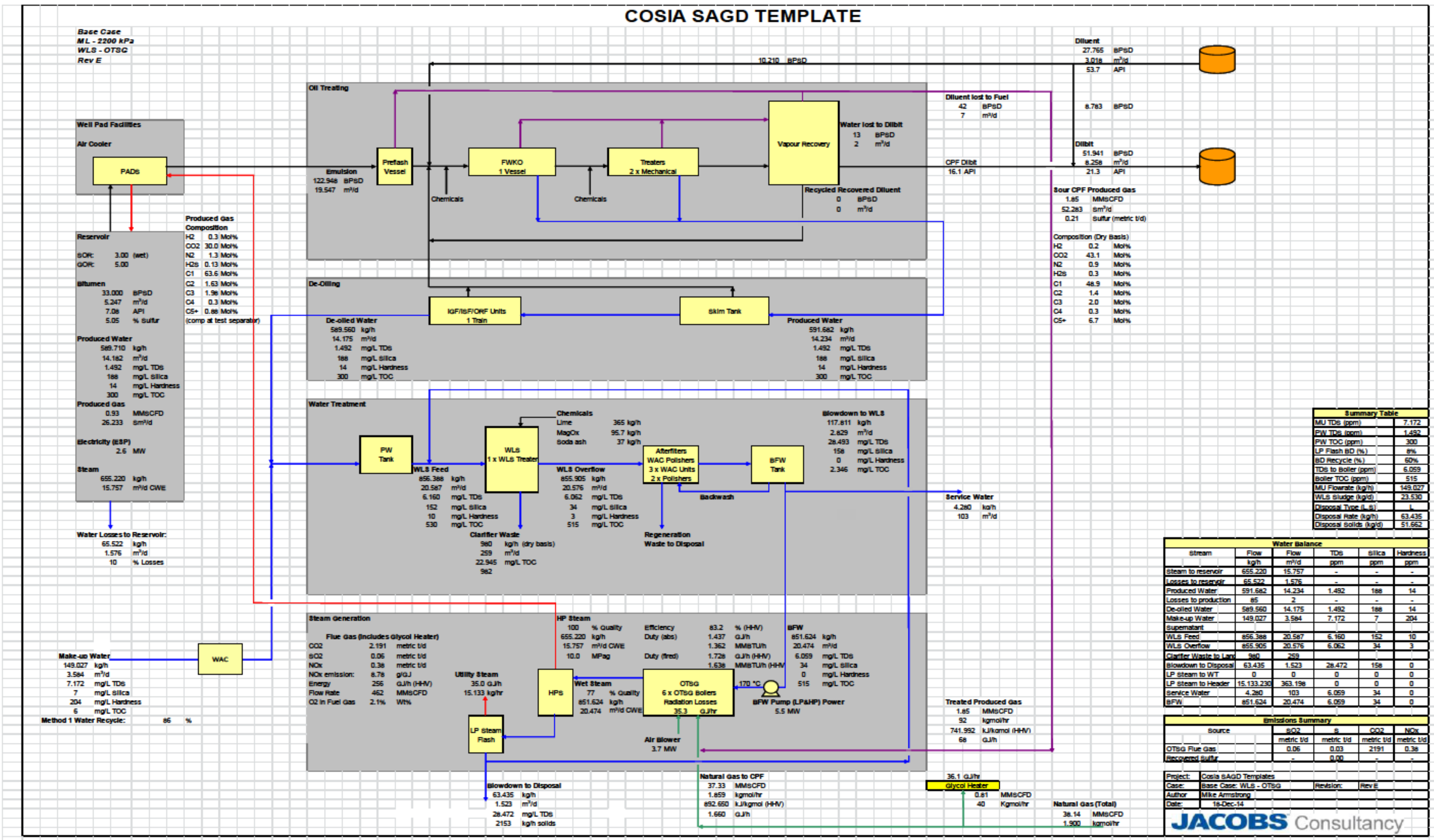


Figure 5. Base Case PFD and Mass Balance of the SAGD CPF. Not shown are the ML at the well pads and electrical system for power import.

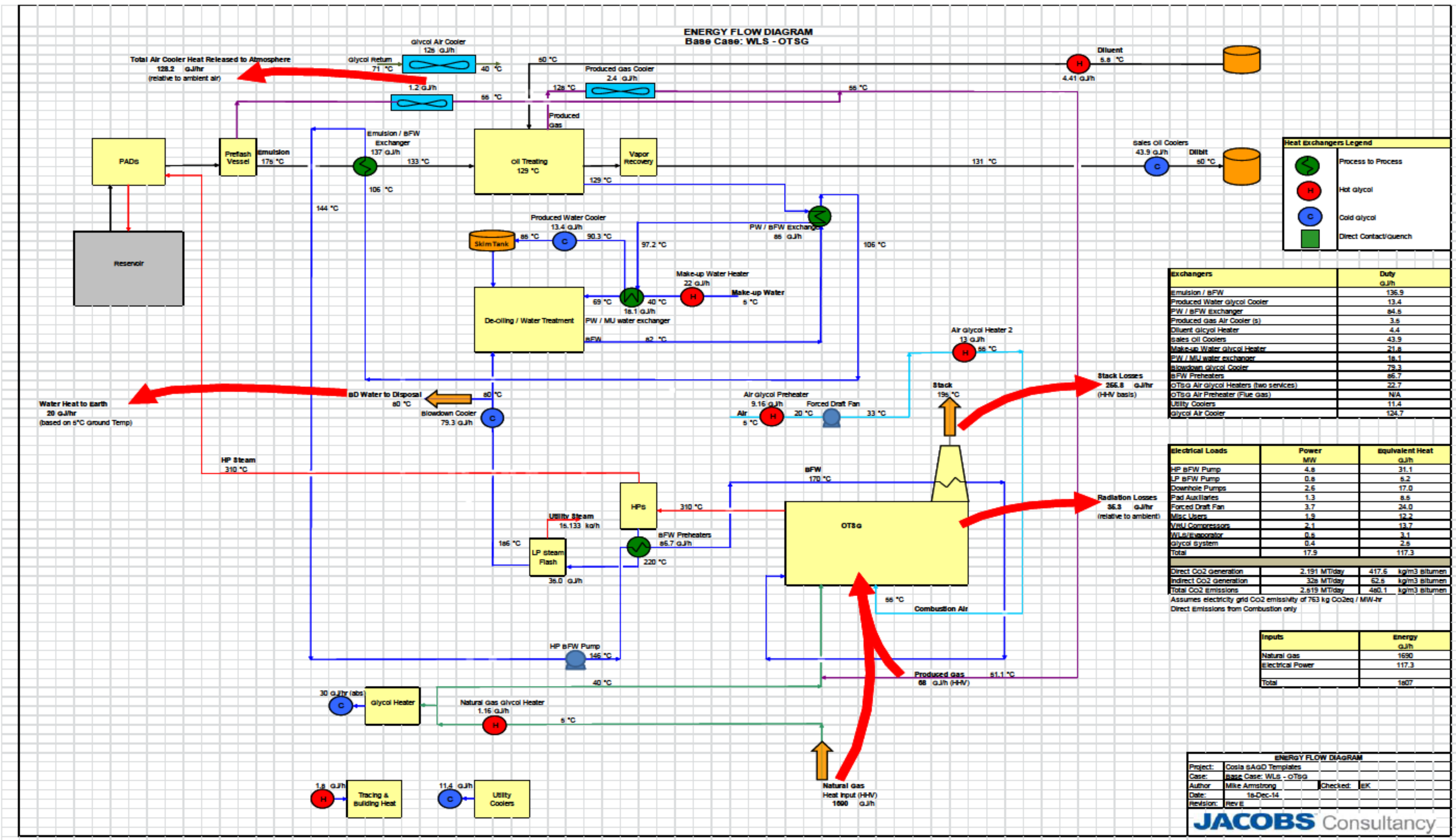


Figure 6: Base Case Energy Flow Diagram of a SAGD CPF.

The WLS process consists of three steps. Firstly, calcium or magnesium oxide is added to the WLS unit to convert calcium or magnesium ions to the less soluble calcium carbonate or magnesium carbonate. The carbonates will flocculate to form larger flocs, which would sink to the bottom of the WLS vessel and are removed and disposed of as wastes. Secondly, the WLS overflow enters filters to remove suspended solids and then thirdly, to WAC units to remove the remaining hardness.[11] The WAC units contain resins with ion exchange sites where the hardness forming ions, typically, Ca^{2+} and Mg^{2+} attach themselves to, and are replaced with other ions, typically Na^{+}, that would not form any hardness. WAC units operate in a batch mode with regenerated units treating the BFW while the remaining units undergo regeneration with hydrochloric acid.

5.4. Steam Generation

The on-spec BFW is sent to the OTSG to generate 77 wt% HP steam of about 9.9 MPa which is the best quality steam consistent with the BFW quality treated with WLS. OTSG are simple commercial boilers that have been used in oil and gas operations for a long time. They are fitted with low NO_x or ultra-low NO_x burners for NO_x emission control. The main reason that 100 wt% steam is not generated in the OTSG is to avoid fouling of the boiler tubes in the OTSG. Premature fouling will necessitate OTSG maintenance that would reduce bitumen production and loss of revenue as a result. The 9.9 MPa HP wet steam is sent to a HP steam separator where 100 wt% HP steam emerges from its top while the bottom liquid steam is sent to a LP steam flash operating at about 1.1 MPa. The LP flash will produce utility steam for the SAGD CPF while the bottom is a liquid stream called blow-down, containing all the dissolved and suspended solids. The blow-down is sent to deep underground wells for disposal.

Note that current oil sands regulations forbid the use of fresh water makeup, and 90% of the produced water must be recycled and re-used. As shown in the water balance in the PFD, the two major water losses are to the reservoir (about 10 wt% of steam injection (CWE)) and blow-down disposal in deep wells (about 10 wt%). To make up for these losses, saline water is brought into the CPF to replenish them. According to the water balance, the make-up is about 23 wt% of SAGD steam requirement (CWE).

5.5. Energy Flow

Figure 6 depicts the energy balance of the 5,247 m^3 per day (m^3/d) SAGD production facility. The two major energy inputs are natural gas mainly for steam generation in the OTSG and electricity imported from the Grid.

The 5,247 m^3/d SAGD project imports 1,696 GJ (HHV) per hour (GJ/h) of pipeline natural gas. A small amount of 36 GJ/h is used in glycol heaters to provide combustion air pre-heat and other minor site demands. Supplemented by 68 GJ/h of produced LPG, a total of 1,728 GJ/h is used in the OTSGs. This facility imports 17.9 MW of electricity from the Grid or 117 GJ/h. The major consumers are HP BFW pumps (26.5%), direct forced draft fan to deliver OTSG combustion air (20.5%), ML (14.5%), and VRU compressors (11.7%).

5.6. Overview of Process and Heat Integration

The primary operational objectives of SAGD CPF are to:

- Produced clean dilbit that is blended with additional diluent to meet pipeline specifications of vapour pressure, density, viscosity and basic sediment and water (BS&W) contents;
- Recover the maximum amount of produced water in order to minimize water make up and to comply with AER regulation of water recycle. Treat the produced water to meet BFW specification; and
- Generate HP Steam for SAGD operation.

From the PFD, it is evident that the three processes are intimately linked. For example, upset in emulsion treating will reduce produced water supply for BFW and would necessitate more make-up water import to generate the same amount of steam. When water treatment process is not performing to design specification of BFW quality, premature fouling of the OTSG boiler tubes may occur. Consequently, OTSG will have to undergo unplanned maintenance, resulting in insufficient steam production and adversely affecting SAGD bitumen production.

The energy flow diagram (EFD) provides several examples of waste heat utilization;

- BFW is pre-heated from water treatment outlet at 82 ^{o}C to 170 ^{o}C before entering the OTSG economizers via a series of heat exchangers, absorbing sensible heat contents in treated oil, inlet emulsion, and then from the HP steam separator blow-down;
- BFW is further pre-heated by OTSG stack gas economizers; and
- Recovery of utility steam from the HP steam separator blow-down for use in bitumen or water treatments;

5.7. GHG Emissions

Each SAGD project emits significant amounts of GHG. Total GHG emissions are 2,519 tonnes per day (t/d) consisting of 2,191 t/d directly from natural gas combustion and 328 t/d indirectly from imported Grid electricity.

In the latter case, the Grid intensity is calculated to be 763 kg per MWh, which is high as the Alberta grid is dominated by coal fired power generation. The SAGD GHG intensity (consisting of CO_2 only) is therefore about 480 kg per m^3 (kg/m^3) or 76 kg per barrel (kg/bbl), of bitumen production, which is 2 to 4 times conventional crude production.[(6)]

Any means to reduce this intensity should be considered. In the subsequent sections, some of them are described, including: using Evaporators to produce higher quality BFW to eliminate blow down and reduce fossil fuel consumption, deploying GL instead of ML to reduce electricity use, or implementing cogeneration on site to partially or completely replace OTSG and eliminate power import.

6. Central Processing Facility #2 (ML-Evap-OTSG)

The process flow Diagram (PFD) and Energy Flow Diagram (EFD) for this CPF#2 are provided in Figures 7 and 8, respectively.

The only change in CPF#2 over CPF#1 is to use Evaporators to replace WLS in water treatment. The ML, oil treatment and steam generation will be similar to those described in Sections 5.1, 5.2 and 5.4.

6.1. Using Evaporators instead of Warm Lime Softening (WLS)

The limitation of WLS in water treatment is that the BFW quality is not good enough to make 100 wt% HP steam in the OTSG. As a result, 77 wt% HP steam is produced in order to avoid pre-mature fouling of the boiler tubes and to make sure that the dissolved solids are contained in the 23 wt% liquid fraction. This means the BFW flow rate is 30% more that the steam requirement (CWE basis) resulting in higher fuel and electricity demands.

One alternative to improving BFW so that much higher quality HP steam can be produced directly is to use Evaporators [12] to replace WLS as shown in Figure 7 below.

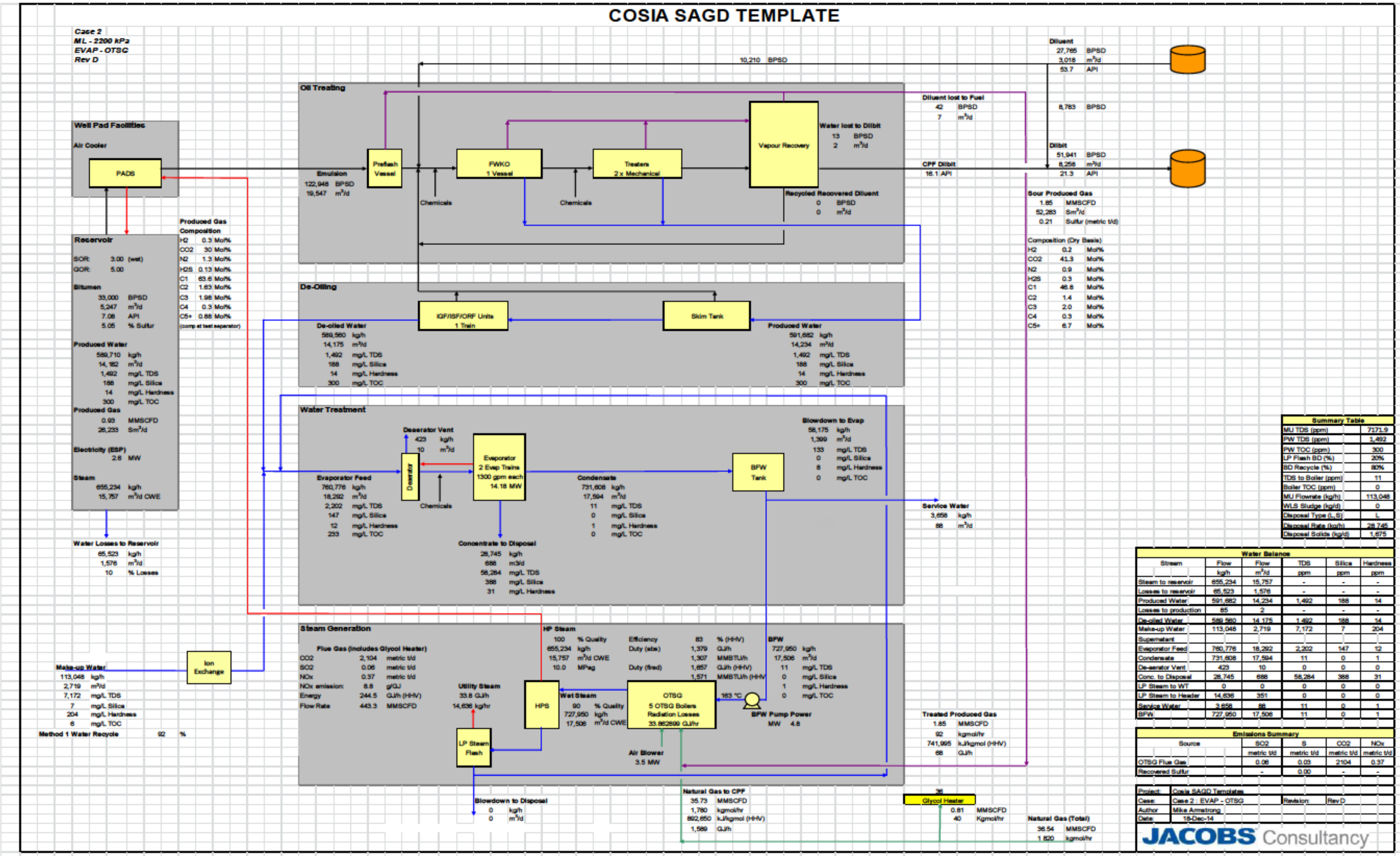
The Evaporators replace WLS, filters and WAC pursuant to the de-oiling process units. The de-oiled produced water, liquid stream from the LP flash and softened make-up saline water are combined and fed into a de-aerator to remove non-condensable gas and oxygen. The de-aerated water is then fed into the Evaporators. Good quality BFW is produced from the condensed vapour stream while all the solids are contained in the liquid underflow which is disposed of as waste off the SAGD site. The remaining hardness is close to zero, achieved in both WLS or Evaporators (see Table 6). The improvements over WLS are in the reductions of total dissolved solids (TDS), silica, and total organic carbon (TOC) contents, respectively from 6,059 to 11 mg per litre (mg/l) for TDS, 34 to 0 mg/l for silica and 515 to 0 mg/l for TOC.

This high quality BFW from Evaporators will allow the direct production of higher HP steam quality than 77 wt%. In this version, 90 wt% is produced from OTSG and sent to the HP steam separator. 100 wt% HP steam emerges from its top and is sent to SAGD wells, while the 10 wt% liquid stream is sent to the LP flash in order to make the required utility steam for site use. The liquid stream from the flash is recycled to the de-aerator as mentioned above.

There are many types of Evaporators. One embodiment uses mechanical vapour compression to provide the heat to vaporize the de-aerated water.[12] Vapour is condensed as high quality BFW while all the solids, silica and hardness are contained in the liquid under-flow stream.

6.2. Overview of Process and Heat Integration

The direct result of using Evaporators is the improved reliability of steam generation resulting from the higher BFW quality. Also, using Evaporators achieves a 15% reduction of BFW requirement, dropping form 851,624 kg per hour (kg/h) in the Base Case using WLS to 727,950 kg/h in Case 2 using Evaporators. Water conservation is improved by 24% per unit of bitumen production (see Table 5). As BFW requirement is reduced, so is the number of OTSGs reduced from 6 to 5. Further the disposal in deep underground wells of high-solid content blow down is replaced with handling of evaporator wastes for off-site disposal. This obviates the application of deep disposal well permit and allays the concern of underground water contamination by the blow-down waste stream.

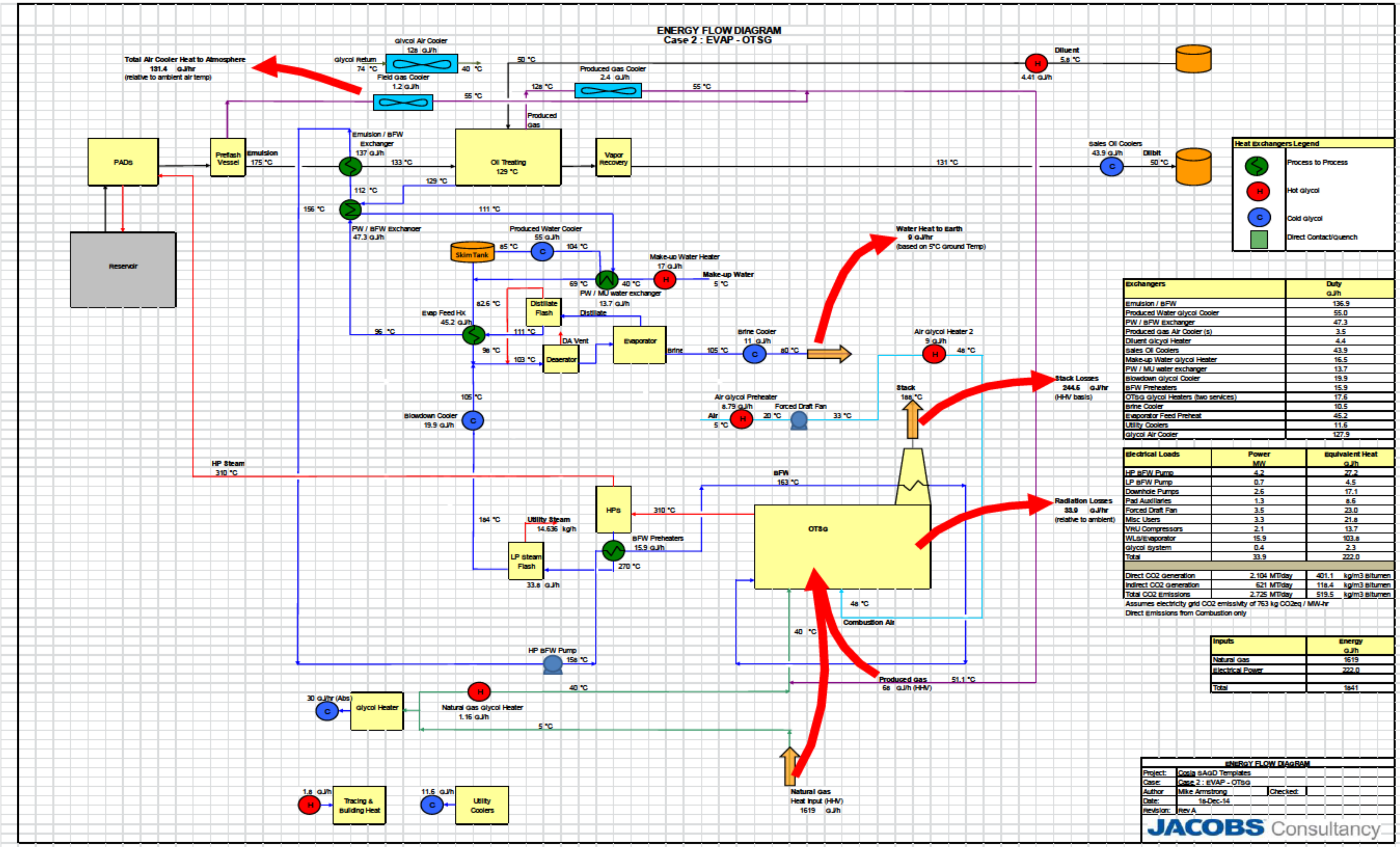


Summary Table	
MU TDS (ppm)	7171.9
PW TDS (ppm)	1,492
PW TOC (ppm)	300
LP Flash BD (%)	20%
BD Recycle (%)	80%
TDS to Boiler (ppm)	11
Boiler TOC (ppm)	0
MU Flowrate (kg/h)	113,048
WLS Sludge (kg/d)	0
Disposal Type (L,S)	L
Disposal Rate (kg/h)	28,745
Disposal Solids (kg/d)	1,675

Water Balance					
Stream	Flow	Flow	TDS	Silica	Hardness
	kg/h	m³/d	ppm	ppm	ppm
Steam to reservoir	655,234	15,757	-	-	-
Losses to reservoir	65,523	1,576	-	-	-
Produced Water	591,682	14,234	1,492	188	14
Losses to production	85	2	-	-	-
De-oiled Water	589,560	14,175	1,492	188	14
Make-up Water	113,048	2,719	7,172	7	204
Supernatant					
Evaporator Feed	760,776	18,292	2,202	147	12
Condensate	731,608	17,594	11	0	1
De-aerator Vent	423	10	0	0	0
Conc. to Disposal	28,745	688	58,284	388	31
LP Steam to WT	0	0	0	0	0
LP Steam to Header	14,636	351	0	0	0
Service Water	3,658	88	11	0	1
BFW	727,950	17,506	11	0	1

Emissions Summary				
Source	SO2	S	CO2	NOx
	metric t/d	metric t/d	metric t/d	metric t/d
OTSG Flue Gas	0.06	0.03	2104	0.37
Recovered Sulfur	-	0.00	-	-

Figure 7.Case 2 PFD and Mass Balance of CPF using Evaporators instead of WLS



Exchangers	Duty GJ/h
Emulsion / BFW	136.9
Produced Water Glycol Cooler	55.0
PW / BFW Exchanger	47.3
Produced Gas Air Cooler (s)	3.5
Diluent Glcyol Heater	4.4
Sales Oil Coolers	43.9
Make-up Water Glycol Heater	16.5
PW / MU water exchanger	13.7
Blowdown Glycol Cooler	19.9
BFW Preheaters	15.9
OTSG Glycol Heaters (two services)	17.6
Brine Cooler	10.5
Evaporator Feed Preheat	45.2
Utility Coolers	11.6
Glycol Air Cooler	127.9

Electrical Loads	Power MW	Equivalent Heat GJ/h
HP BFW Pump	4.2	27.2
LP BFW Pump	0.7	4.5
Downhole Pumps	2.6	17.1
Pad Auxiliaries	1.3	8.6
Forced Draft Fan	3.5	23.0
Misc Users	3.3	21.8
VRU Compressors	2.1	13.7
WLS/Evaporator	15.9	103.8
Glycol System	0.4	2.3
Total	33.9	222.0
Direct CO2 Generation	2,104 MT/day	401.1 kg/m3 Bitumen
Indirect CO2 Generation	621 MT/day	118.4 kg/m3 Bitumen
Total CO2 Emissions	2,725 MT/day	519.5 kg/m3 Bitumen

Assumes electricity grid CO2 emissivity of 763 kg CO2eq / MW-hr
Direct Emissions from Combustion only

Inputs	Energy GJ/h
Natural Gas	1619
Electrical Power	222.0
Total	1841

Figure 8: Case 2 Energy Flow Diagram of CPF Using Evaporators Instead of WLS.

The attendant impacts of using Evaporators are the minor reduction of fuel requirement but a significant increase of electricity use. In the former, per unit of bitumen production, fuel requirement drops 2% from 8.7 GJ per m^3 bitumen (GJ/m^3) to 8.6 GJ/m^3 (see Table 5). Power requirement escalates from 17.9 MW to 33.9 MW, an increase of 89%. This results directly from using mechanical vapour compression as a means to provide heat to vapourize BFW.

There is no significant change in process integration vis-à-vis the Base Case.

Figure 8 shows the energy flow of CPF#2. As the Evaporators use electricity to make high quality BFW, there is little chance of integrating with or extracting waste heat from, the other parts of SAGD CPF as they are entirely thermal.

6.3. GHG Emissions

As electricity is imported from the GHG intensive Grid which is dominated by coal fired power generation, the GHG emissions increase by 8% from 480 to 519 kg/m^3 (76 to 83 kg/bbl) of bitumen produced. The reduction in direct emissions from fossil fuel consumption cannot entirely offset the increase from the indirect emissions of Grid electricity import.

7. Central Processing Facility #3 (GL-WLS-OTSG)

The process flow Diagram (PFD) and Energy Flow Diagram (EFD) for this CPF#3 are provided in Figures 9 and 10, respectively.

The only change in CPF#3 over CPF#1 is to use gas lift (GL) to replace mechanical lift (ML) or electrical submersible pumps (ESPs) for oil production. The oil and water treatments, and steam generation will be similar to those described in Sections 5.2, 5.3 and 5.4.

7.1. Gas Lift (GL) Replacing Mechanical Lift (ML)

The majority of SAGD production design employs electrical submersible pumps (ESP) to pump emulsion from the Producers to the surface. Before ESPs have become as reliable as they are now, GL was employed to push emulsion to the surface. Figure 9 depicting the PFD and mass balance of this case where GL replaces ESP. It shows essentially the same processes as those of the Base Case. The exception is the elimination of a pre-Flash vessel (PFV). In the current configuration, the natural gas used in the GL, after it is separated from the emulsion, joins the LPG recovered from the VRU for use in the OTSG.

In the GL design, HP pipeline natural gas is injected into the annulus of the producer.[13] At the bottom of the Producer annulus, it enters its tubing through gas lift valves to aerate the collected emulsion, thus reducing its density and the hydrostatic head of the emulsion in the tubing. The natural gas pressure must be high enough to overcome this hydrostatic head and push the emulsion to the surface. For deeper oil sands reservoirs, the natural gas pressure may not be high enough and GL cannot be deployed. Other negative effects of GL vis-à-vis ML have already been described in Section 1.

GL accomplishes two objectives. The first is to produce emulsion to the surface without any mechanical devices and electricity consumption. The second is the de-pressurization of HP pipeline natural gas. The burners of the OTSG require much lower pressure than is supplied directly from the pipeline. Without GL to reduce its pressure in the Producers, the HP natural gas has to be de-pressurized through a letdown valve or small gas turbine.

7.2. Overview of Process and Heat Integration

In the Case 3 design, 36% of the total natural gas fuel requirement of 1,817 GJ/h is used in the GL. After pushing the emulsion to the surface, the lifting gas joins up with the remaining natural gas for steam generation in the OTSG. Relative to the Base Case, fuel requirement is increased slightly by 6% (See Table 5). The higher fuel requirement is offset by the 16% lower demand of power, reducing from 17.9 MW to 15.1 MW, relative to the Base Case (see Figure 10). Make-up water demand has increased by 6% according to this design.

As seen in Figure 10, there is virtually no change in terms of process and heat integration vis-à-vis the Base Case when GL is used instead of ESP.

7.3. GHG Emissions

GHG emission intensity (as represented by CO_2) increases slightly by 2% to 490 kg/m^3 (78 kg/bbl) of bitumen production.

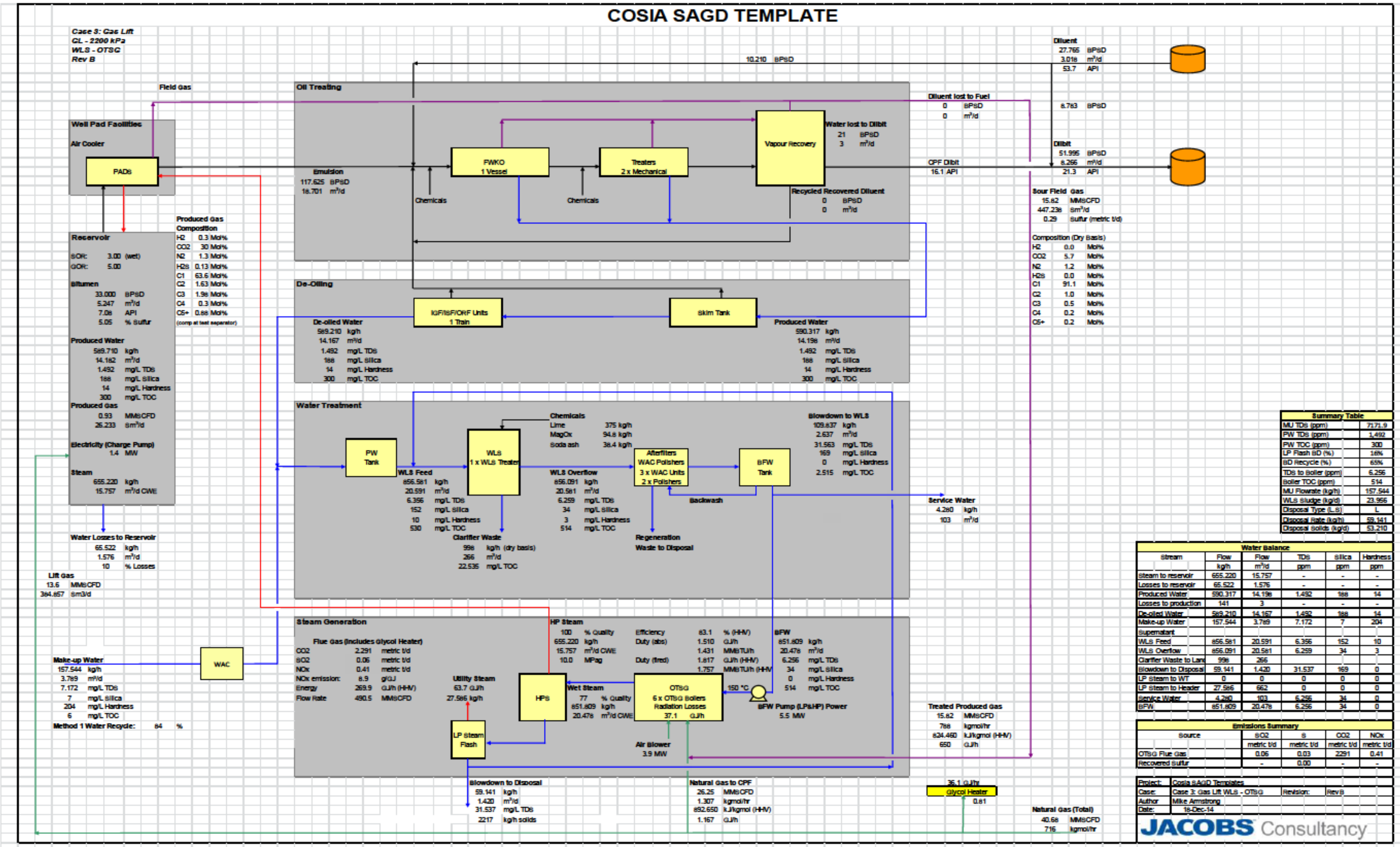
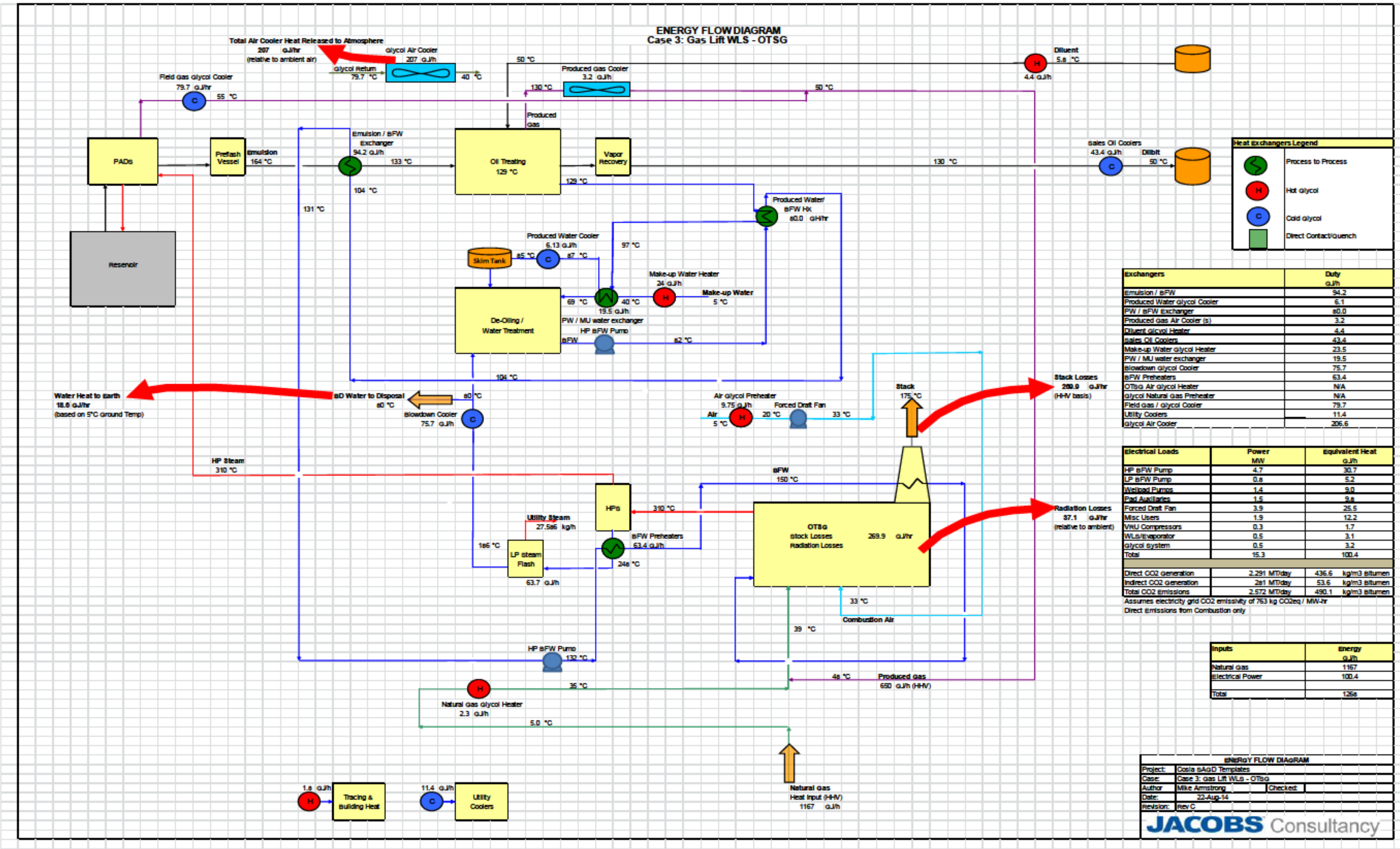


Figure 9: Case 3 PFD and Mass Balance using GL to Replace ML.



Exchangers	Duty GJ/h
Emulsion / BFW	94.2
Produced Water Glycol Cooler	6.1
PW / BFW Exchanger	80.0
Produced Gas Air Cooler (s)	3.2
Diluent Glycol Heater	4.4
Sales Oil Coolers	43.4
Make-up Water Glycol Heater	23.5
PW / MU water exchanger	19.5
Blowdown Glycol Cooler	75.7
BFW Preheaters	63.4
OTSG Air Glycol Heater	N/A
Glycol Natural Gas Preheater	N/A
Field Gas / Glycol Cooler	79.7
Utility Coolers	11.4
Glycol Air Cooler	206.6

Electrical Loads	Power MW	Equivalent Heat GJ/h
HP BFW Pump	4.7	30.7
LP BFW Pump	0.8	5.2
Wellpad Pumps	1.4	9.0
Pad Auxiliaries	1.5	9.8
Forced Draft Fan	3.9	25.5
Misc Users	1.9	12.2
VRU Compressors	0.3	1.7
WLS/Evaporator	0.5	3.1
Glycol System	0.5	3.2
Total	15.3	100.4
Direct CO2 Generation	2.291 MT/day	436.6 kg/m3 Bitumen
Indirect CO2 Generation	281 MT/day	53.6 kg/m3 Bitumen
Total CO2 Emissions	2.572 MT/day	490.1 kg/m3 Bitumen

Assumes electricity grid CO2 emissivity of 763 kg CO2eq / MW-hr
Direct Emissions from Combustion only

Inputs	Energy GJ/h
Natural Gas	1167
Electrical Power	100.4
Total	1268

ENERGY FLOW DIAGRAM			
Project:	Cosia SAGD Templates		
Case:	Case 3: Gas Lift WLS - OTSG		
Author	Mike Armstrong	Checked:	
Date:	22-Aug-14		
Revision:	Rev C		

JACOBS Consultancy

Figure 10: Case 3 Energy Flow Diagram using GL to Replace ML.

8. Central Processing Facility #4 (ML-WLS-OTSG-Cogen)

The process flow Diagram (PFD) and Energy Flow Diagram (EFD) for this CPF#4 are provided in Figures 11 and 12, respectively.

The only change in CPF#4 over CPF#1 is to add cogeneration to eliminate power import and augment OTSG steam generation. The ML, oil and water treatments, and OTSG steam generation will be similar to those described in Sections 5.1, 5.2 and 5.4.

8.1. Using Cogeneration + OTSG instead of just OTSG

Cogeneration in oil sands is a commercial practice in SAGD CPF. It consists of using gas turbine (GT) for electricity production and heat recovery steam generator (HRSG) for HP steam production.[(6)] Both GT and HRSG are commercial technologies. In this design, a 43 MW cogeneration plant is implemented in a SAGD CPF with the same water treatment by WLS and emulsion production by ML as the Base Case (see Figure 11).

Candor is not privy to the reasons for selecting the size of the GT or HRSG. The 43 MW GE 6B GT is available commercially. Once the GT is selected, the amount of sensible heat in the GT exhaust will be provided by its vendor. The HRSG design provides flexibility with respect to the amount of duct burning (DB) or force-air duct burning (FADB) or both, to augment the sensible heat in the GT exhaust.[(6)] The sizing of the HRSG is therefore contingent on the apportionment of the total HP steam generation to the HRSG and OTSG. The higher the HRSG share, the higher requirement of DB or FADB, and the fewer number of remaining OTSG. In this design, 4 OTSG are deployed to produce 67% of total HP steam requirement of 851,661 kg/h. As a result, a HRSG that incorporates 320 GJ/h DB is selected to produce the remaining 33% of HP steam. In other words, the HRSG supplants 2 OTSGs. After supplying on site electricity requirement, 26 MW of excess power is available for export.

In HRSG DB, the combustion of the added natural gas does not require additional combustion air as there is sufficient oxygen left in the GT exhaust to satisfy the combustion need. As a result, the size of the forced draft air blowers will be reduced. In choosing DB, the HRSG combustion chamber volume must be properly designed to achieve high combustion efficiency.[(6)]

The total fuel consumption has increased by 5% vis-à-vis the Base Case to 1,909 GJ/h. 43% of this total is needed for cogeneration. The GT needs about 500 GJ/h of natural gas in order to produce 43 MW at a heat rate of 11.6 GJ per MWh or at a generation efficient of 31%, which is typical of single cycle gas turbine efficiency.

Case 4 does not affect the water consumption vis-à-vis the Base Case as it uses WLS to make BFW.

8.2. Overview of Process and Heat Integration

Case 4's process flow is similar to the Base Case; the exception is the addition of a 43 MW GT and the associated HRSG. With the replacement of 2 OTSG by one HRSG, there will be some minor changes in the BFW and HP steam distribution systems in the SAGD CPF. As DB relies on the oxygen in the GT exhaust for combustion, Case 4's power demand is reduced slightly from the Base Case's 17.9 MW to 16.6 MW. Case 4's EFD depicts two separate flue gas sources, one for the OTSGs and the other from the HRSG, at the same exit temperature of 195 ^{o}C vis-à-vis the single source from the OTSG's in the Base Case.

8.3. GHG Emissions

Alberta's Specified Gas Emitters Regulations (SGER) provide a method to allocate emissions to cogeneration electricity and steam. It deems the cogeneration electricity exported to the Grid at GHG intensity equal to an efficient natural gas combined cycle, and steam generation efficient of 80% (HHV basis). For the former, it is assumed to be 390 kg per MWh (kg/MWh) for Alberta. In applying the SGER allocation, the emissions from the 26 MW power export at 390 kg/MWh is subtracted from the total cogeneration emissions and the balance is allocated to the steam.[6] Using the SGER allocation methodology, an offset of 247 t/d or 47.1 kg/m3 (7.5 kg/bbl) of bitumen produced from the 26 MW power export would result in a net intensity of 433 kg/m^3 (69 kg/bbl). If, however, the export power output of 26 MW is allowed an offset at the Grid intensity of 763 kg/MWh, the offset credits would be 92 kg/m^3 (14.6 kg/bbl), which would lower the SAGD intensity further to 388 kg/m^3 (61.7 kg/bbl) as shown in Table 5.

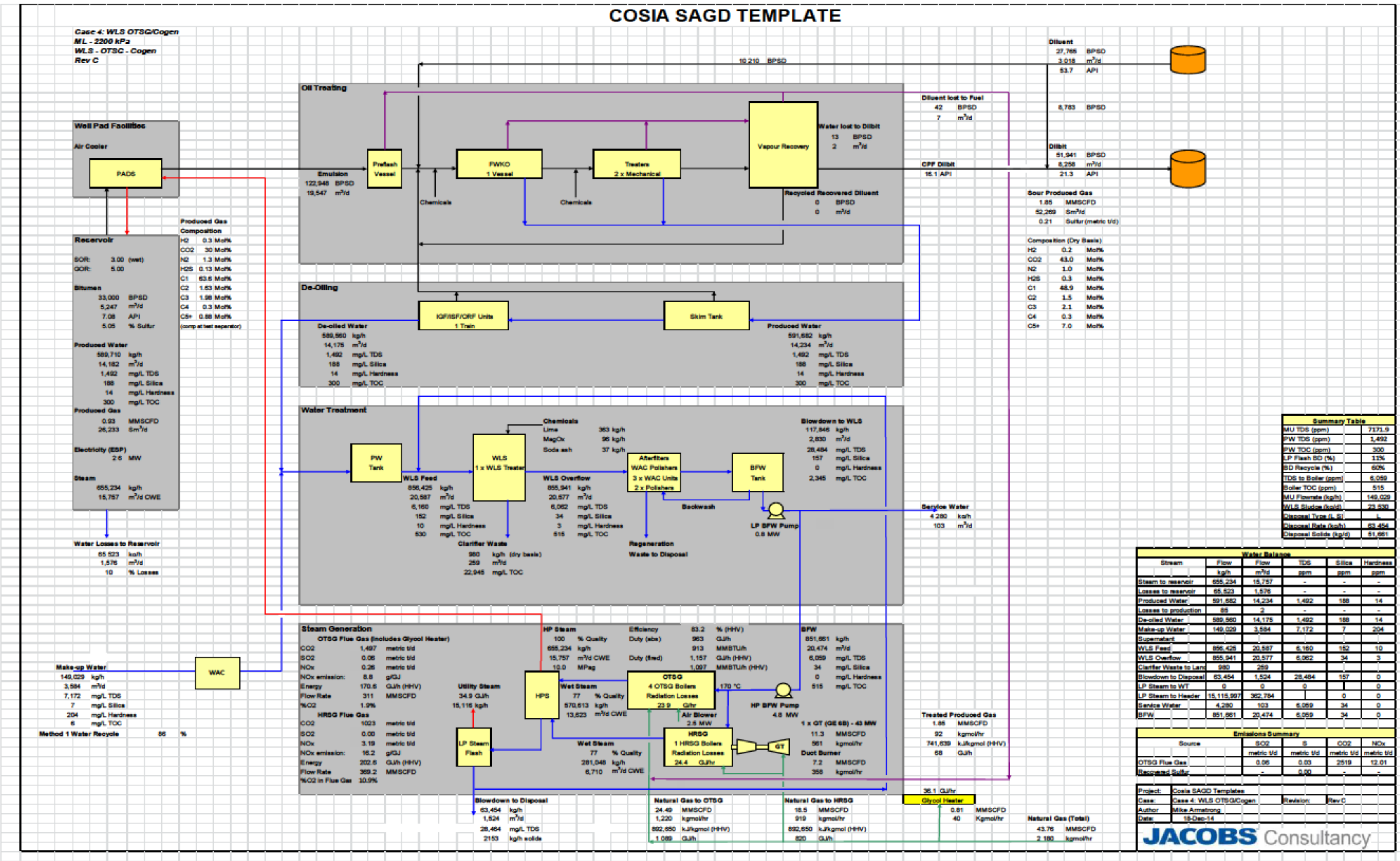
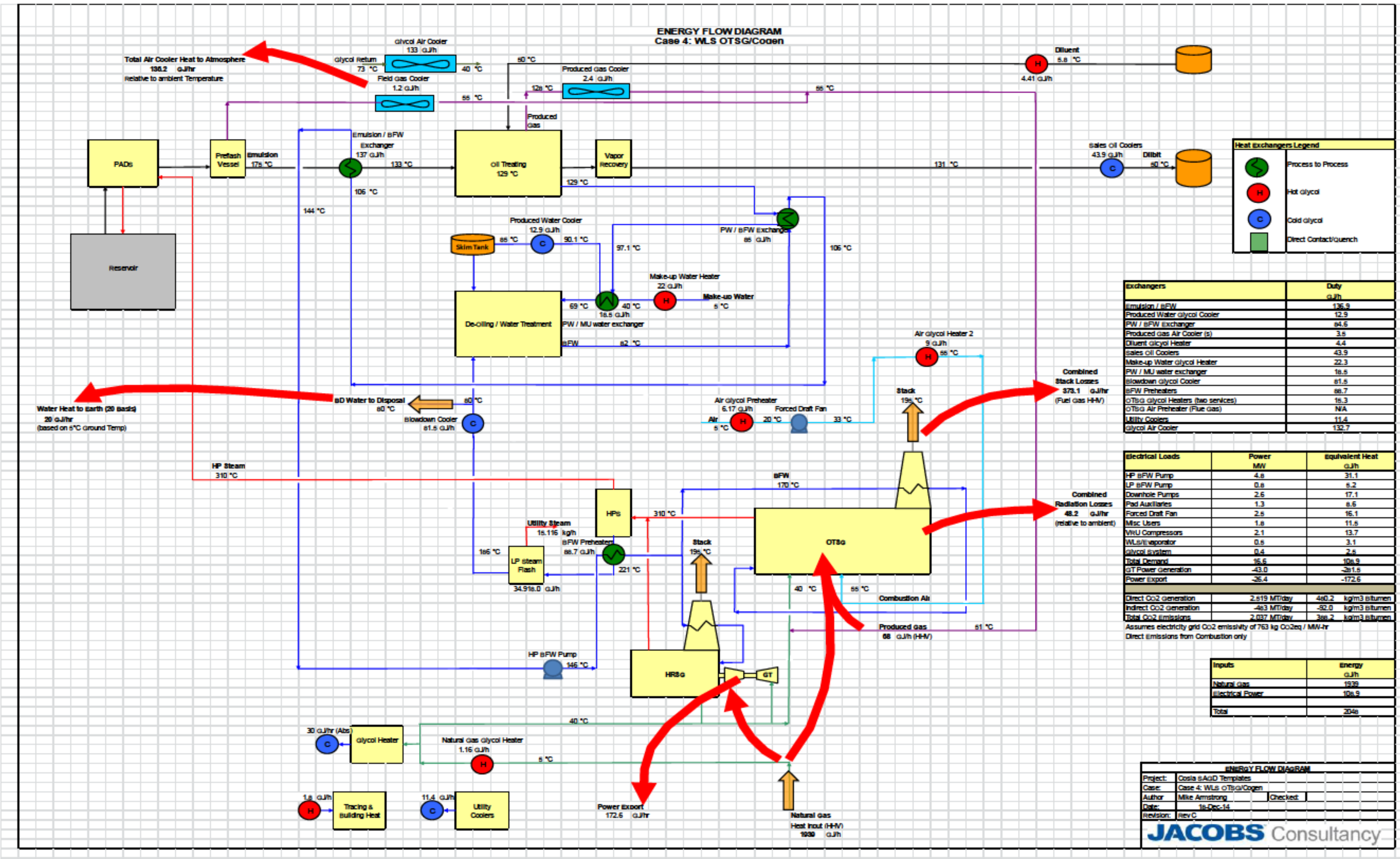


Figure 11: Case 4 PFD and Mass Balance with Cogeneration added to Base Case to eliminate Power Import and 2 OTSG.



Exchangers	Duty GJ/h
Emulsion / BFW	136.9
Produced Water Glycol Cooler	12.9
PW / BFW Exchanger	84.6
Produced Gas Air Cooler (s)	3.6
Diluent Glcyol Heater	4.4
Sales Oil Coolers	43.9
Make-up Water Glycol Heater	22.3
PW / MU water exchanger	18.5
Blowdown Glycol Cooler	61.5
BFW Preheaters	88.7
OTSG Glycol Heaters (two services)	15.3
OTSG Air Preheater (Flue Gas)	N/A
Utility Coolers	11.4
Glycol Air Cooler	132.7

Electrical Loads	Power MW	Equivalent Heat GJ/h
HP BFW Pump	4.8	31.1
LP BFW Pump	0.8	5.2
Downhole Pumps	2.6	17.1
Pad Auxiliaries	1.3	8.6
Forced Draft Fan	2.5	16.1
Misc Users	1.8	11.5
VRU Compressors	2.1	13.7
WLS/Evaporator	0.5	3.1
Glycol System	0.4	2.5
Total Demand	16.6	108.9
GT Power Generation	-43.0	-281.5
Power Export	-26.4	-172.6
Direct CO2 Generation	2,519 MT/day	480.2 kg/m3 Bitumen
Indirect CO2 Generation	-483 MT/day	-92.0 kg/m3 Bitumen
Total CO2 Emissions	2,037 MT/day	388.2 kg/m3 Bitumen

Inputs	Energy GJ/h
Natural Gas	1939
Electrical Power	108.9
Total	2048

Figure 12: Case 4 Energy Flow with Cogeneration added to Base Case to eliminate Power Import and 2 OTSG.

9. Central Processing Facility #5 (ML-Evap-OTSG-Cogen)

The process flow Diagram (PFD) and Energy Flow Diagram (EFD) for this CPF#5 are provided in Figures 13 and 14, respectively.

The changes in CPF#5 over CPF#1 include the use of cogeneration to eliminate power import and augment OTSG steam generation, as well as Evaporators to replace WLS in the water treatment. The ML, oil treatment and OTSG steam generation will be similar to those described in Sections 5.1, 5.2 and 5.4.

9.1. Using Cogeneration + OTSG instead of just OTSG AND using Evaporators instead of just WLS

CPF#5 attempts to capture the combined benefits of cogeneration to eliminate import power and Evaporators for greater water conservation. Descriptions of Evaporators and cogeneration have been provided respectively in CPF#2 and 4. They will not be repeated here. The PFD and material balance for Case 5 is shown below in Figure 13.

As described in CPF#4, the GT is a 43 MW GE 6B. The water balance is similar to CPF#2 resulting in similar benefit of water conservation vis-à-vis WLS for water treatment. Steam generation apportionment between HRSG with DB is similar to CPF#4. The one big difference between this Case and CPF#4 is the amount of power export has declined to 10.3 MW as a result of greater on site demand from the Evaporators.

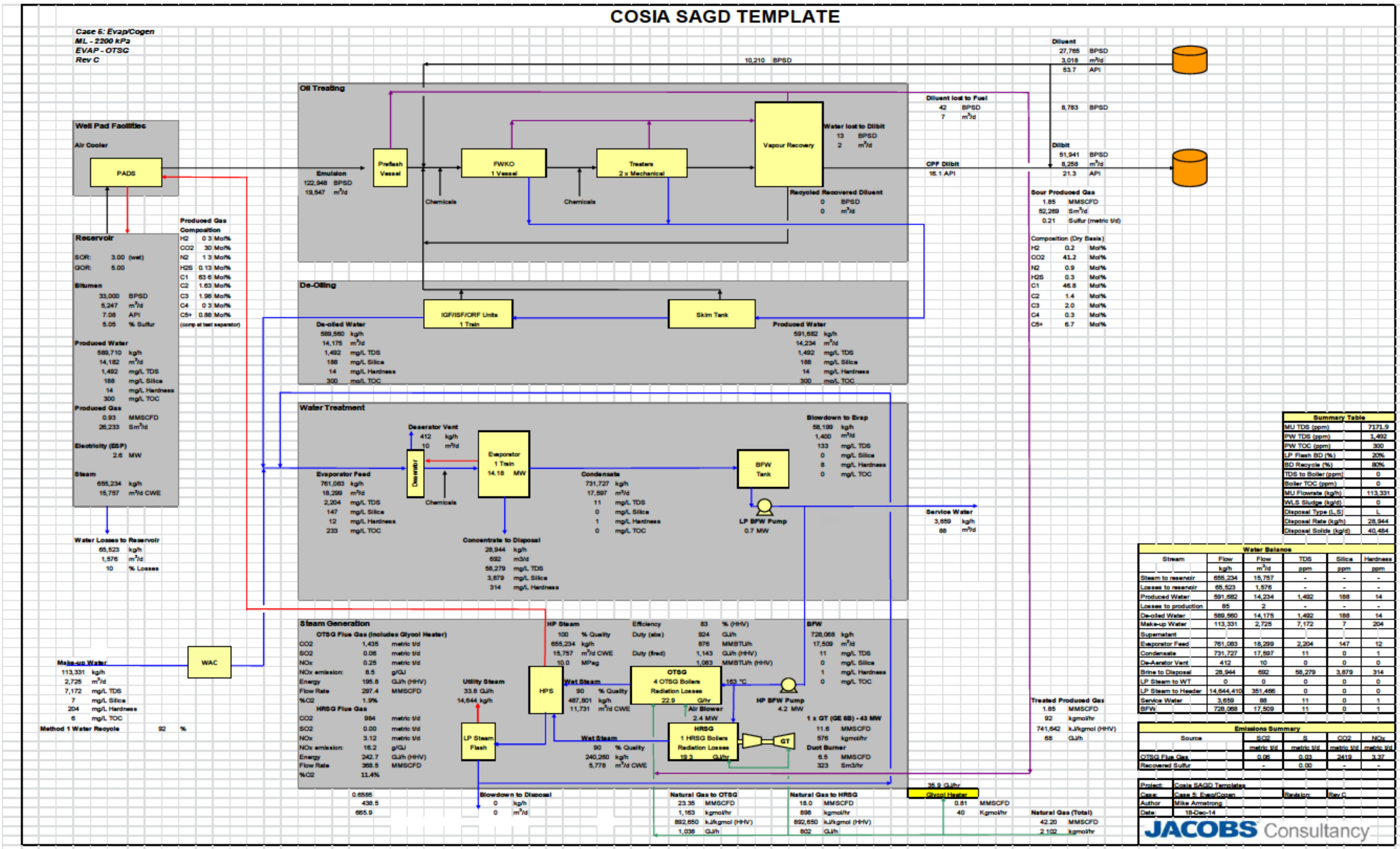
9.2. Overview of Process and Heat Integration

As the Evaporators produce much higher quality BFW, total natural gas requirement is reduced to 1,840 GJ/h in this case vis-à-vis 1,909 GJ/h in CPF#4. The higher quality BFW also requires less DB in the HRSG, dropping to 288 GJ/h in this case from 319 GJ/h in CPF#4 (These numbers are calculated from the respective PFDs). Figure 14 depicts the energy balance of CPF#5.

As the HRSG DB does not require combustion air delivered by forced draft fans, the power requirement of air blowers is reduced by 1.3 MW vis-à-vis the Base Case. Offsetting this reduction is the need to provide electricity to the Evaporators. Their requirements are about 15.6 MW, similar to those in CPF#2. This accounts for the reduced power export from 26 MW in CPF#4 to 10 MW in the current case. Other than these observations, the energy flows are similar to Case 4.

9.3. GHG emissions

According to the SGER, the export of 10.3 MW of power would have resulted in offset credits of 96.4 t/d, which will lower SAGD GHG intensity by 96.4 t/d. The corresponding reduction of SAGD GHG intensity would be 18 kg/m^3 (2.9 kg/bbl) of bitumen produced, i.e., from 461 kg/m^3 to 443 kg/m^3 (73.2 to 70.3 kg/bbl) of bitumen. If however the export power of 10.3 MW is allowed an offset at the Grid intensity of 763 kg/MWh, the offset credits would be 35.9 kg/m^3 (5.7 kg/bbl) of bitumen produced, which would lower the SAGD intensity further to 425 kg/m^3 (67.6 kg/bb) as shown in Table 5.



Summary Table	
MU TDS (ppm)	7171.9
PW TDS (ppm)	1,492
PW TOC (ppm)	300
LP Flash BD (%)	20%
BD Recycle (%)	80%
TDS to Boiler (ppm)	0
Boiler TOC (ppm)	0
MU Flowrate (kg/h)	113,331
WLS Sludge (kg/d)	0
Disposal Type (L,S)	L
Disposal Rate (kg/h)	28,944
Disposal Solids (kg/d)	40,484

Water Balance					
Stream	Flow	Flow	TDS	Silica	Hardness
	kg/h	m³/d	ppm	ppm	ppm
Steam to reservoir	655,234	15,757	-	-	-
Losses to reservoir	65,523	1,576	-	-	-
Produced Water	591,682	14,234	1,492	188	14
Losses to production	85	2	-	-	-
De-oiled Water	589,560	14,175	1,492	188	14
Make-up Water	113,331	2,725	7,172	7	204
Supernatant					
Evaporator Feed	761,083	18,299	2,204	147	12
Condensate	731,727	17,597	11	0	1
De-Aerator Vent	412	10	0	0	0
Brine to Disposal	28,944	692	58,279	3,879	314
LP Steam to WT	0	0	0	0	0
LP Steam to Header	14,644,410	351,466	0	0	0
Service Water	3,659	88	11	0	1
BFW	728,068	17,509	11	0	1

Emissions Summary				
Source	SO2	S	CO2	NOx
	metric t/d	metric t/d	metric t/d	metric t/d
OTSG Flue Gas	0.06	0.03	2419	3.37
Recovered Sulfur	-	0.00	-	-

Figure 13: Case 5 PFD and Mass Balance of adding Cogeneration to Case 2 to Eliminate Power Import and 2 OTSG.

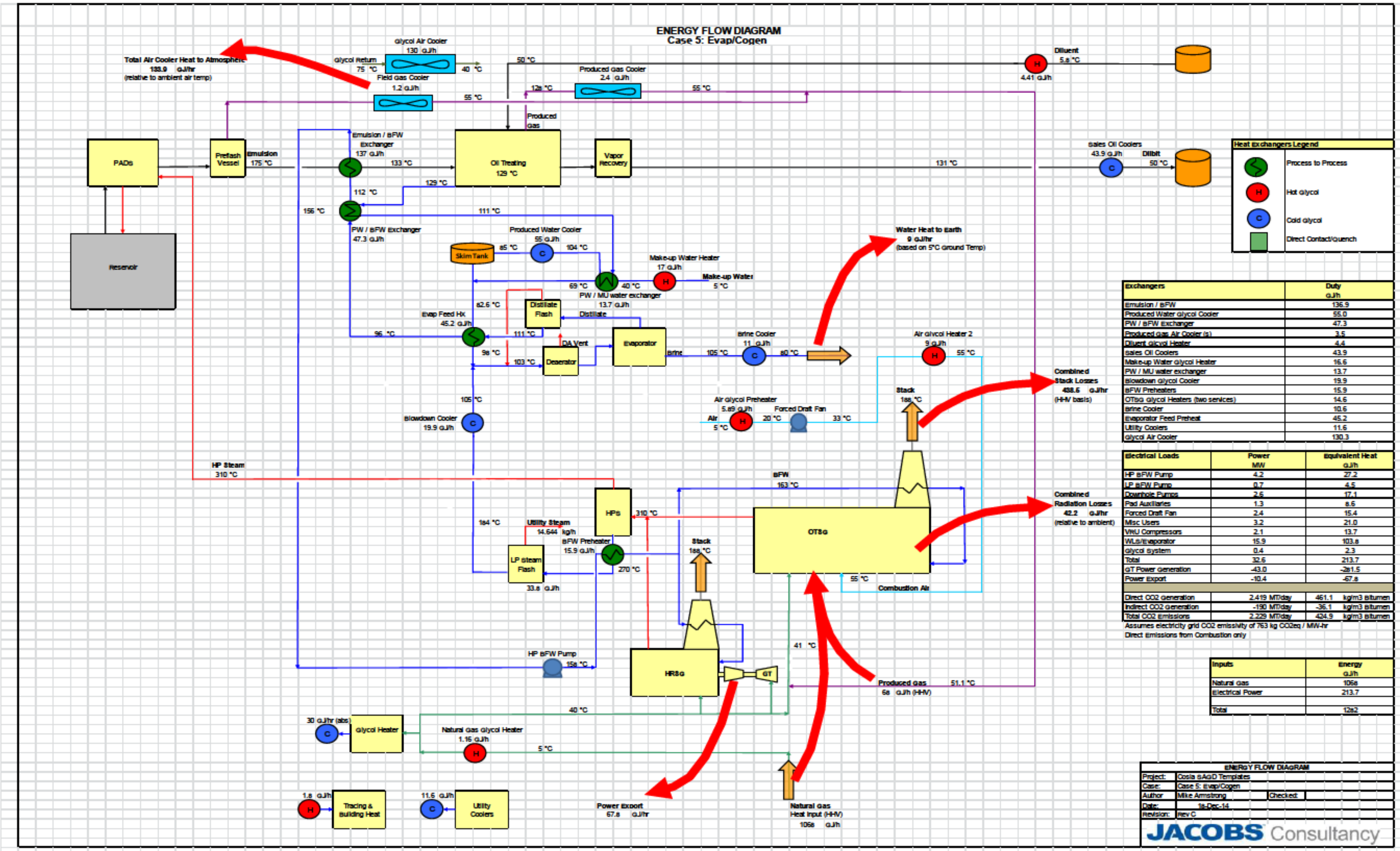


Figure 14: Case 5 Energy Flow Diagram of adding Cogeneration to Case 2 to Eliminate Power Import and 2 OTSG

10. Central Processing Facility #6 (ML-WLS-Cogen)

The process flow Diagram (PFD) and Energy Flow Diagram (EFD) for this CPF#6 are provided in Figures 15 and 16, respectively.

The only change in CPF#6 over CPF#1 is to use cogeneration to eliminate power import and OTSG steam generation. The ML, oil and water treatments will be similar to those described in Sections 5.1, 5.2 and 5.3.

10.1. Using Cogeneration to replace OTSG

In the CPF#6 design, the objective is to meet the total HP steam and site power requirements using cogeneration. As described elsewhere [(6)], cogeneration in SAGD is an established practice commercially. It typically employs heat recovery steam generator (HRSG) for HP steam production replacing OTSG, and gas turbine (GT) to produce electricity concurrently, eliminating power import from the Grid. As WLS is continued to be used for water treatment, the BFW quality is only good enough to generate wet steam of 77 wt% quality from the HRSG. The process flow diagram and material balance is shown in Figure 15 below:

In CPF#6, the HRSG has to meet the entire steam requirement for bitumen production. This is the main distinction from Case 4 or 5 where HP steam requirement is jointly met by HRSG and OTSG.

Candor is not privy to the design of this cogeneration. An 88 MW GE 7E plus HRSG was chosen. The GT vendor will provide the available GT exhaust sensible heat to the HRSG. In order to generate the 851,624 kg/h of 77 wt% HP steam requirements by HRSG alone, DB will be deployed to augment the 88 MW GT exhaust to produce the required steam. As shown in Figure 15, the total natural gas requirement is 2,165 GJ/h, split almost equally between GT (1,048 GJ/h) and HRSG DB (1,117 GJ/h). The latter is augmented with 68 GJ/h of recovered LPG for a total of 1,185 GJ/h.

With the exception of cogeneration (GT+HRSG) replacing the OTSG and power import, the remainder of the process flow and the entire material balance are identical to the Base Case. In terms of natural gas requirement, CPF#6 requires 23% more than the Base Case per unit of production, mainly due to higher power generation.

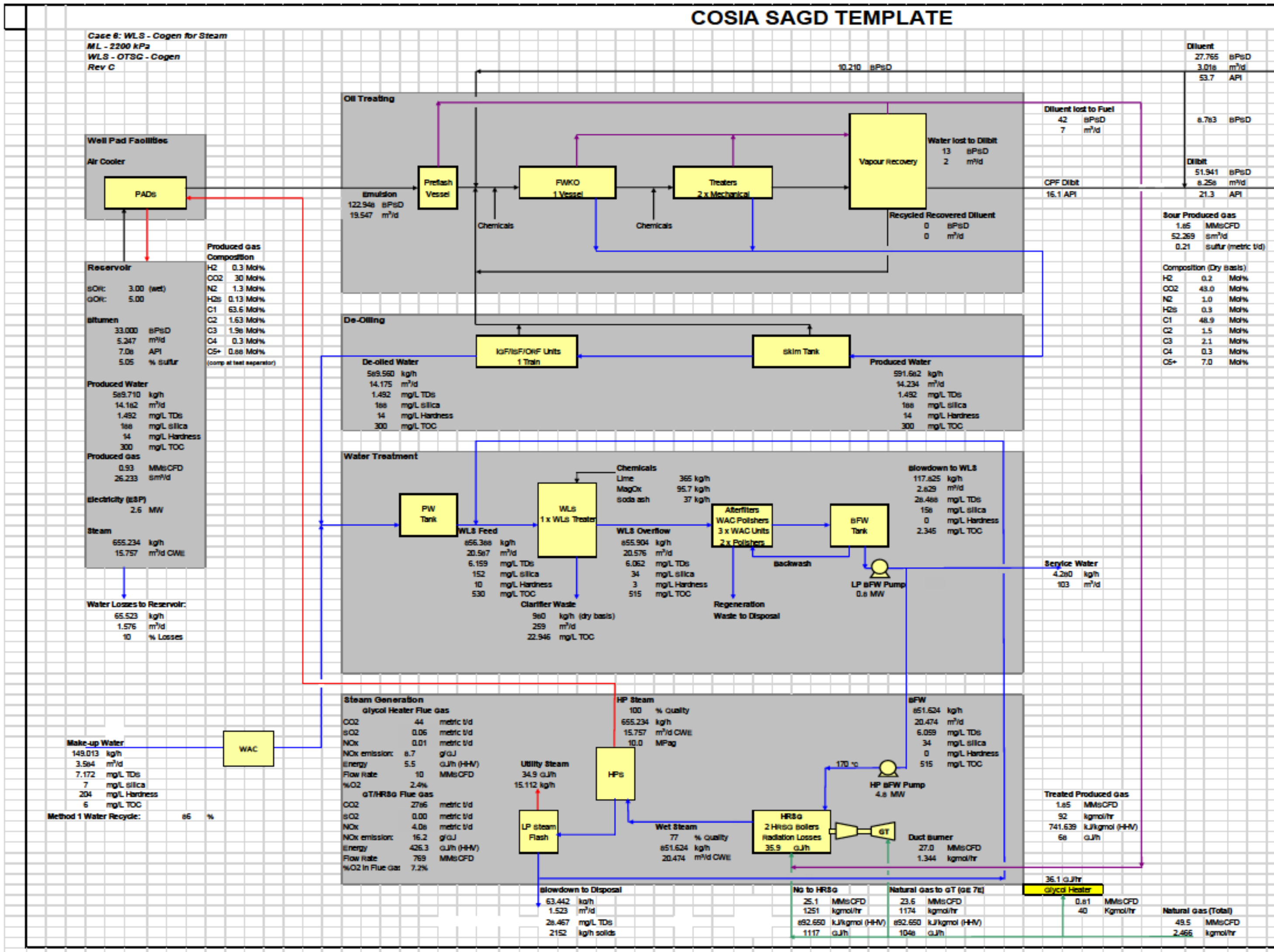
10.2. Overview of Process and Energy Integration

The process integration is identical to the Base Case, although as there are only two HRSGs instead of six OTSG, the BFW and steam distribution systems in the CPF#6 will be different than the Base Case. CPF#6's energy flows are shown in Figure 16.

The major difference in energy integration vis-à-vis the Base Case is the source of electricity. In the Base Case, power is imported from the Grid. In the current case, it is generated on site from the GT. Part of its output is used to satisfy the various requirements in CPF#6. The one major change in power demand vis-à-vis the Base Case is that forced draft air blowers to deliver combustion air to the OTSG are no longer required as the DB in the HRSG does not required combustion air, relying on the oxygen in the GT exhaust instead. As a result, site power demand drops from 17.9 MW to 13.9 MW. The net power export from the 88 MW GT is therefore 74 MW.

10.3. GHG Emissions

The direct emission intensity is calculated to be 539 kg/m^3 of bitumen produced. According to the SGER allocation methodology for cogeneration electricity, the offset credit from exporting 74 MW power is equivalent to 132 kg/m^3 (21 kg/bbl) of produced bitumen. Therefore, the net SAGD emission intensity is 407 kg/m^3 (64.7 kg/bbl) of produced bitumen. If the export electricity would get offset credit at the Grid intensity of 763 kg/MWh, the net SAGD emission intensity would be 281 kg/m^3 (44.7 kg/bbl) of produced bitumen as shown in Table 5. Relative to the Base Case, this would be 42% improvement if the offset credits are set at the Grid GHG intensity.



Summary Table	
MU TDS (ppm)	7171.9
PW TDS (ppm)	1,492
PW TOC (ppm)	300
LP Flash BD (%)	11%
BD Recycle (%)	60%
TDS to Boiler (ppm)	6.059
Boiler TOC (ppm)	515
MU Flowrate (kg/h)	149.013
WLS Sludge (kg/d)	23.530
Disposal Type (L,S)	L
Disposal Rate (kg/h)	63.442
Disposal Solids (kg/d)	51.659

Water Balance

Stream	Flow kg/h	Flow m³/d	TDS ppm	Silica ppm	Hardness ppm
Steam to reservoir	655.234	15.757	-	-	-
Losses to reservoir	65.523	1.576	-	-	-
Produced Water	591.682	14.234	1.492	188	14
Losses to production	85	2	-	-	-
De-oiled Water	589.560	14.175	1.492	188	14
Make-up Water	149.013	3.584	7.172	7	204
Supernatant					
WLS Feed	856.388	20.587	6.159	152	10
WLS Overflow	855.904	20.576	6.062	34	3
Clarifier Waste to Lan	980	259			
Blowdown to Disposal	63.442	1.523	28.488	158	0
LP Steam to WT	0	0	-	-	-
LP Steam to Header	15.112	363	-	-	-
Service Water	4.280	103	6.059	34	0
BFW	851.624	20.474	6.059	34	0

Emissions Summary

Source	SO2 metric t/d	S metric t/d	CO2 metric t/d	NOx metric t/d
OTSG Flue Gas	0.06	0.03	2.830	8.69
Recovered Sulfur	-	0.00	-	-

Project:	Cosia SAGD Templates		
Case:	Case 6: WLS - Cogen for Steam	Revision:	Rev C
Author	Mike Armstrong		
Date:	18-Dec-14		

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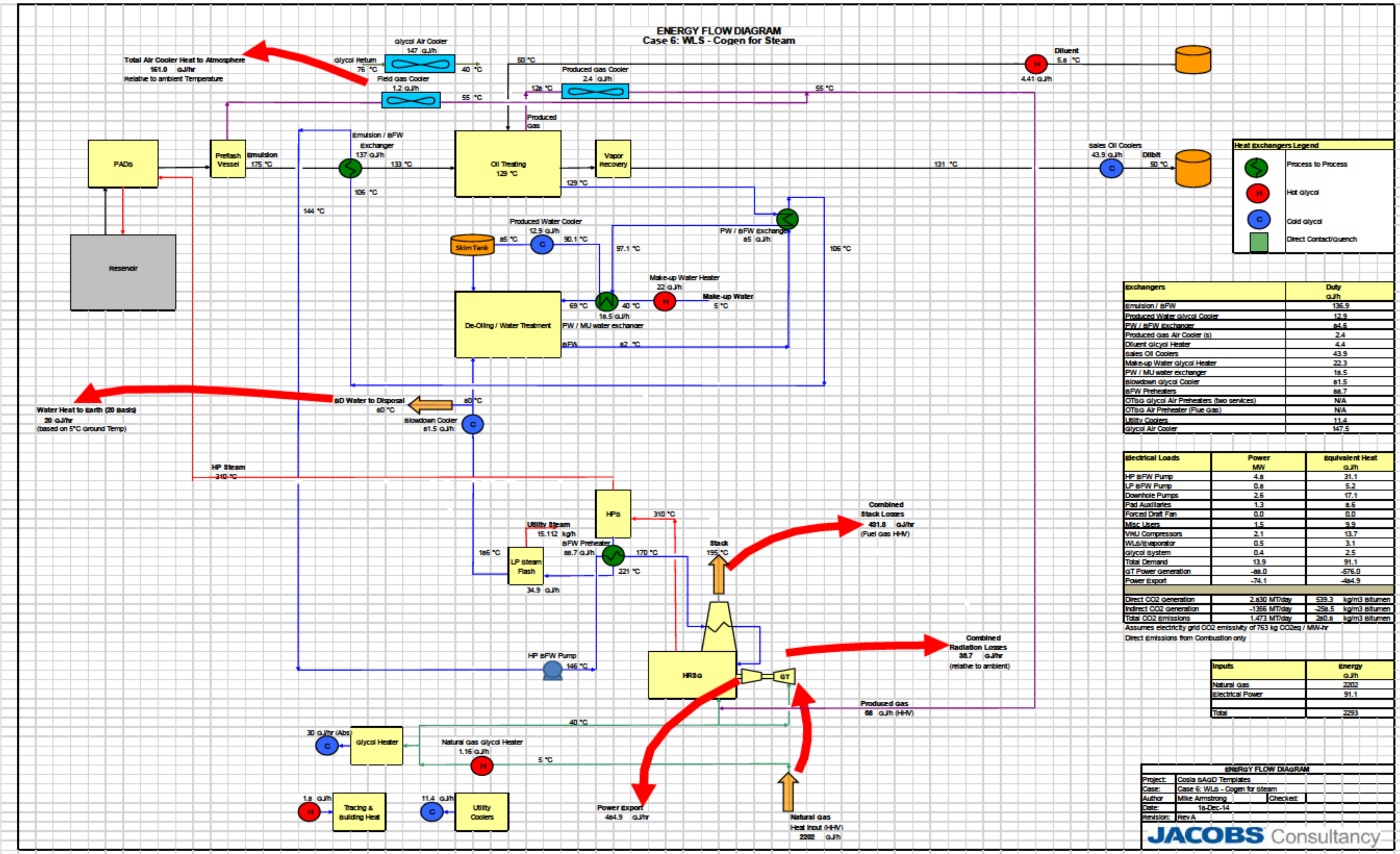
Figure 15: Case 6 PFD and Mass Balance of full Cogeneration with ML and WLS



Exchangers	Duty GJ/h
Emulsion / BFW	136.9
Produced Water Glycol Cooler	12.9
PW / BFW Exchanger	84.6
Produced Gas Air Cooler (s)	2.4
Diluent Glycol Heater	4.4
Sales Oil Coolers	43.9
Make-up Water Glycol Heater	22.3
PW / MU water exchanger	18.5
Blowdown Glycol Cooler	81.5
BFW Preheaters	88.7
OTSG Glycol Air Preheaters (two services)	N/A
OTSG Air Preheater (Flue Gas)	N/A
Utility Coolers	11.4
Glycol Air Cooler	147.5

Electrical Loads	Power MW	Equivalent Heat GJ/h
HP BFW Pump	4.8	31.1
LP BFW Pump	0.8	5.2
Downhole Pumps	2.6	17.1
Pad Auxillaries	1.3	8.6
Forced Draft Fan	0.0	0.0
Misc Users	1.5	9.9
VRU Compressors	2.1	13.7
WLS/Evaporator	0.5	3.1
Glycol System	0.4	2.5
Total Demand	13.9	91.1
GT Power Generation	-88.0	-576.0
Power Export	-74.1	-484.9
Direct CO2 Generation	2,830 MT/day	539.3 kg/m3 Bitumen
Indirect CO2 Generation	-1356 MT/day	-258.5 kg/m3 Bitumen
Total CO2 Emissions	1,473 MT/day	280.8 kg/m3 Bitumen

Assumes electricity grid CO2 emissivity of 763 kg CO2eq / MW-hr

Direct Emissions from Combustion only

Inputs	Energy GJ/h
Natural Gas	2202
Electrical Power	91.1
Total	2293

ENERGY FLOW DIAGRAM			
Project:	Cosia SAGD Templates		
Case:	Case 6: WLS - Cogen for Steam		
Author	Mike Armstrong	Checked:	
Date:	18-Dec-14		
Revision:	Rev A		

Figure 16: Case 6 Energy Flow Diagram of full Cogeneration with ML and WLS.

11. References

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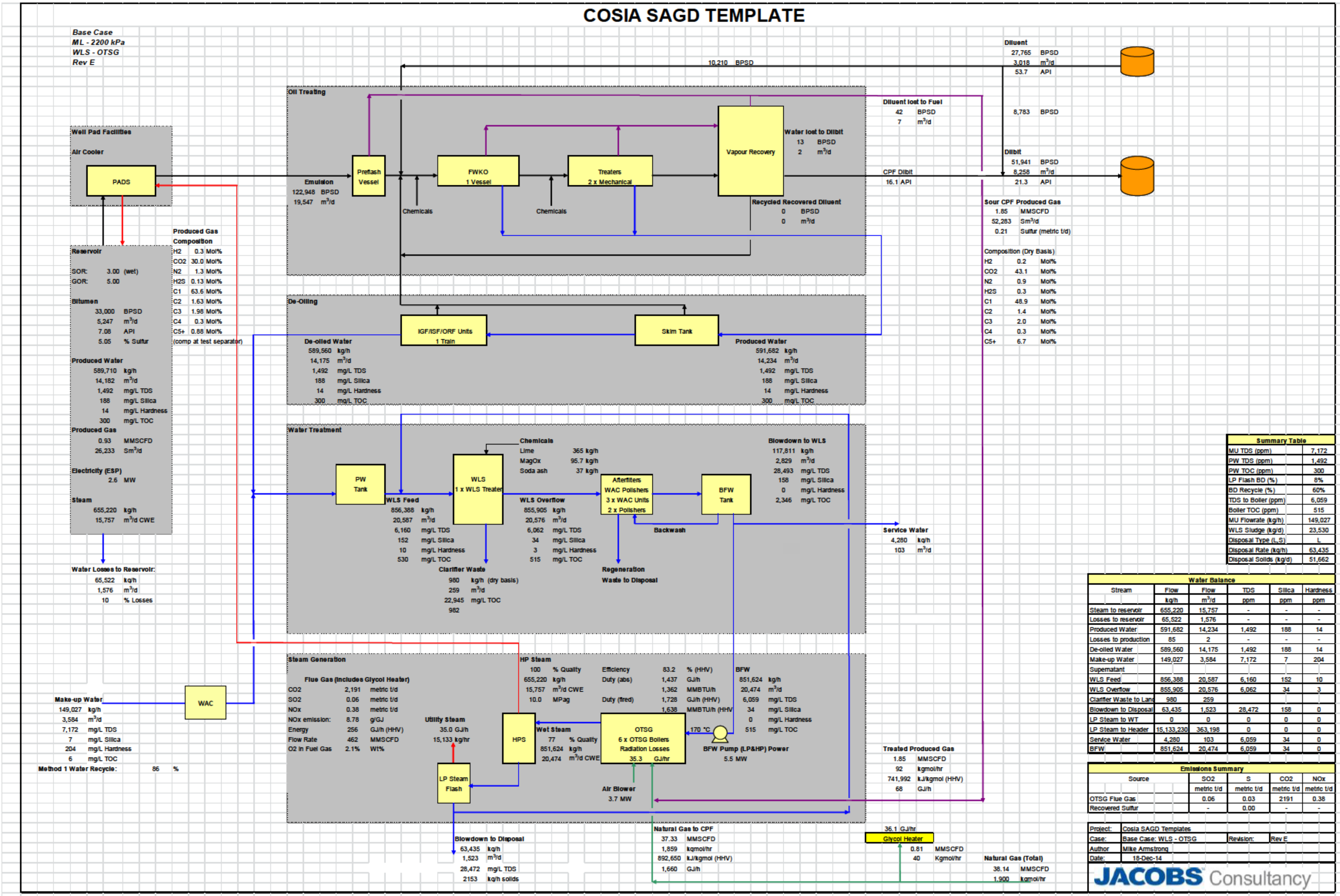
12. Appendices: Process Flow Diagrams, Mass Balances, Utilities and Energy Flow Diagrams provided by COSIA

12.1 Base Case CPF



Summary Table	
MU TDS (ppm)	7,172
PW TDS (ppm)	1,492
PW TOC (ppm)	300
LP Flash BD (%)	8%
BD Recycle (%)	60%
TDS to Boiler (ppm)	6,059
Boiler TOC (ppm)	515
MU Flowrate (kg/h)	149,027
WLS Sludge (kg/d)	23,530
Disposal Type (L,S)	L
Disposal Rate (kg/h)	63,435
Disposal Solids (kg/d)	51,662

Water Balance					
Stream	Flow	Flow	TDS	Silica	Hardness
	kg/h	m³/d	ppm	ppm	ppm
Steam to reservoir	655,220	15,757	-	-	-
Losses to reservoir	65,522	1,576	-	-	-
Produced Water	591,682	14,234	1,492	188	14
Losses to production	85	2	-	-	-
De-oiled Water	589,560	14,175	1,492	188	14
Make-up Water	149,027	3,584	7,172	7	204
Supernatant					
WLS Feed	856,388	20,587	6,160	152	10
WLS Overflow	855,905	20,576	6,062	34	3
Clarifier Waste to Land	980	259			
Blowdown to Disposal	63,435	1,523	28,472	158	0
LP Steam to WT	0	0	0	0	0
LP Steam to Header	15,133,230	363,198	0	0	0
Service Water	4,280	103	6,059	34	0
BFW	851,624	20,474	6,059	34	0

Emissions Summary				
Source	SO2	S	CO2	NOx
	metric t/d	metric t/d	metric t/d	metric t/d
OTSG Flue Gas	0.06	0.03	2191	0.38
Recovered Sulfur	-	0.00	-	-

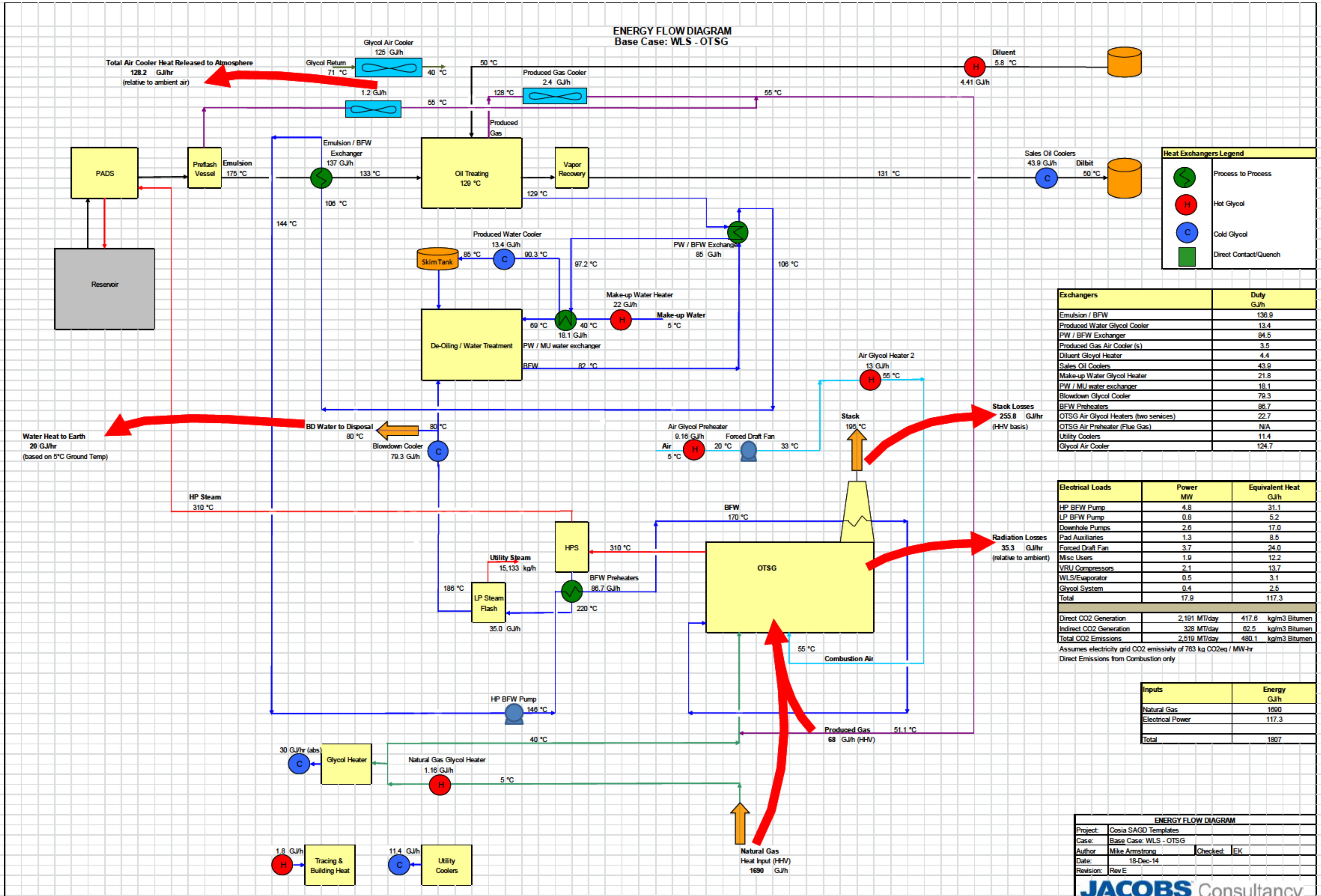
Project:	Cosia SAGD Templates		
Case:	Base Case: WLS - OTSG	Revision:	Rev E
Author	Mike Armstrong		
Date:	18-Dec-14		

Project:	Cosia SAGD Templates
Case:	Base Case: WLS - OTSG Rev E
Author:	Mike Armstrong
Date:	18-Dec-14

Utilities Summary

Process Unit	Capacity	Unit	Commodity	Power kW	Steam (positive=generation) HP kg/h	LP kg/hr	Fuel Produced Gas MMSCFD	Natural Gas MMSCFD	CO2 metric t/d
Well Pads	33,000	BPD	Bitumen						
Steam Injected to Wells					-655,220				
ESP Pumps				2,596					
Auxiliaries*				1,298					
Pumpjacks									
Oil Treatment	122,948	BPD	Emulsion						
Pumps				88					
De-oiling	89,158	BPD	De-oiled Water						
Pumps				153					
VRU Compressors				2,088					
Water Treating	89,526	BPD	Produced Water						
Pumps				51					
WLS				425					
Steam Generation	20,474	m3/d CWE	Wet Steam						
Air Blower				3,666					
OTSG					655,220	15,133	1.85	37.33	2,147
Pumps				5,543					
Offsites									
Sulphur	0.00	metric t/d	Sulfur						
Glycol	22,003	m3/d	Glycol	381				0.81	44
Misc				1,629					
Total Power				17,919					

*** Wellpad auxiliaries are assumed to be 50% of ESP power requirements**



Exchangers	Duty GJ/h
Emulsion / BFW	136.9
Produced Water Glycol Cooler	13.4
PW / BFW Exchanger	84.5
Produced Gas Air Cooler (s)	3.5
Diluent Glcyol Heater	4.4
Sales Oil Coolers	43.9
Make-up Water Glycol Heater	21.8
PW / MU water exchanger	18.1
Blowdown Glycol Cooler	79.3
BFW Preheaters	86.7
OTSG Air Glycol Heaters (two services)	22.7
OTSG Air Preheater (Flue Gas)	N/A
Utility Coolers	11.4
Glycol Air Cooler	124.7

Electrical Loads	Power MW	Equivalent Heat GJ/h
HP BFW Pump	4.8	31.1
LP BFW Pump	0.8	5.2
Downhole Pumps	2.6	17.0
Pad Auxiliaries	1.3	8.5
Forced Draft Fan	3.7	24.0
Misc Users	1.9	12.2
VRU Compressors	2.1	13.7
WLS/Evaporator	0.5	3.1
Glycol System	0.4	2.5
Total	17.9	117.3
Direct CO2 Generation	2,191 MT/day	417.6 kg/m3 Bitumen
Indirect CO2 Generation	328 MT/day	62.5 kg/m3 Bitumen
Total CO2 Emissions	2,519 MT/day	480.1 kg/m3 Bitumen

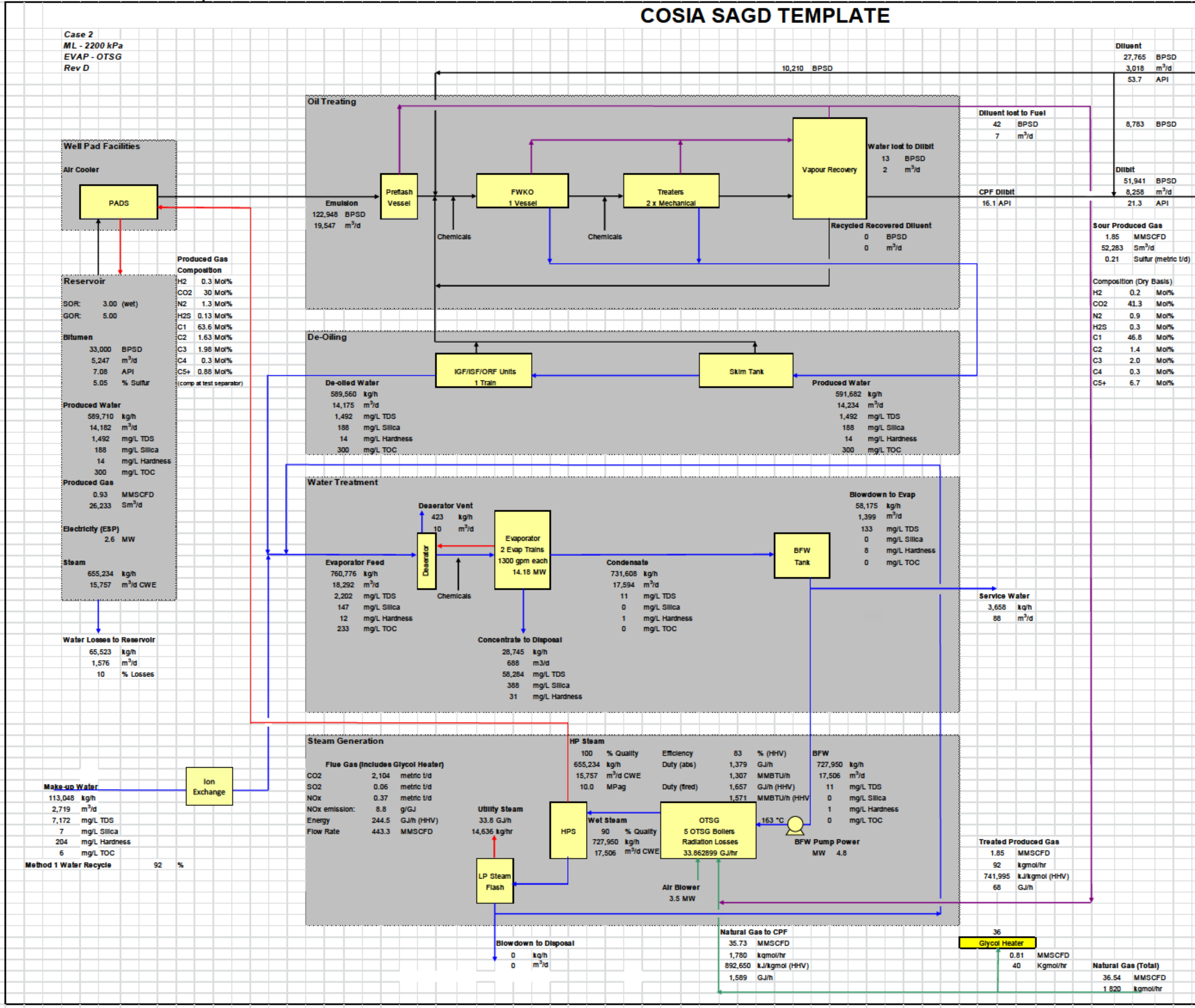
Assumes electricity grid CO2 emissivity of 763 kg CO2eq / MW-hr
Direct Emissions from Combustion only

Inputs	Energy GJ/h
Natural Gas	1690
Electrical Power	117.3
Total	1807

ENERGY FLOW DIAGRAM			
Project:	Cosia SAGD Templates		
Case:	Base Case: WLS - OTSG		
Author	Mike Armstrong	Checked:	EK
Date:	18-Dec-14		
Revision:	Rev E		

JACOBS Consultancy

12.2 CPF#2: ML-Evap-OTSG



Summary Table	
MU TDS (ppm)	7171.9
PW TDS (ppm)	1,492
PW TOC (ppm)	300
LP Flash BD (%)	20%
BD Recycle (%)	80%
TDS to Boiler (ppm)	11
Boiler TOC (ppm)	0
MU Flowrate (kg/h)	113,048
WLS Sludge (kg/d)	0
Disposal Type (L,S)	L
Disposal Rate (kg/h)	28 745
Disposal Solids (kg/d)	1,675

Water Balance

Stream	Flow	Flow	TDS	Silica	Hardness
	kg/h	m³/d	ppm	ppm	ppm
Steam to reservoir	655,234	15,757	-	-	-
Losses to reservoir	65,523	1,576	-	-	-
Produced Water	591,682	14,234	1,492	188	14
Losses to production	85	2	-	-	-
De-oiled Water	589 560	14 175	1 492	188	14
Make-up Water	113,048	2,719	7,172	7	204
Supernatant					
Evaporator Feed	760,776	18,292	2,202	147	12
Condensate	731,608	17,594	11	0	1
De-aerator Vent	423	10	0	0	0
Conc. to Disposal	28,745	688	58,284	388	31
LP Steam to WT	0	0	0	0	0
LP Steam to Header	14,636	351	0	0	0
Service Water	3 658	88	11	0	1
BFW	727,950	17,506	11	0	1

Emissions Summary

Source	SO2	S	CO2	NOx
	metric t/d	metric t/d	metric t/d	metric t/d
OTSG Flue Gas	0.06	0.03	2104	0.37
Recovered Sulfur	-	0.00	-	-

Project:	Cosia SAGD Templates		
Case:	Case 2 : EVAP - OTSG	Revision:	Rev D
Author	Mike Armstrong		
Date:	18-Dec-14		

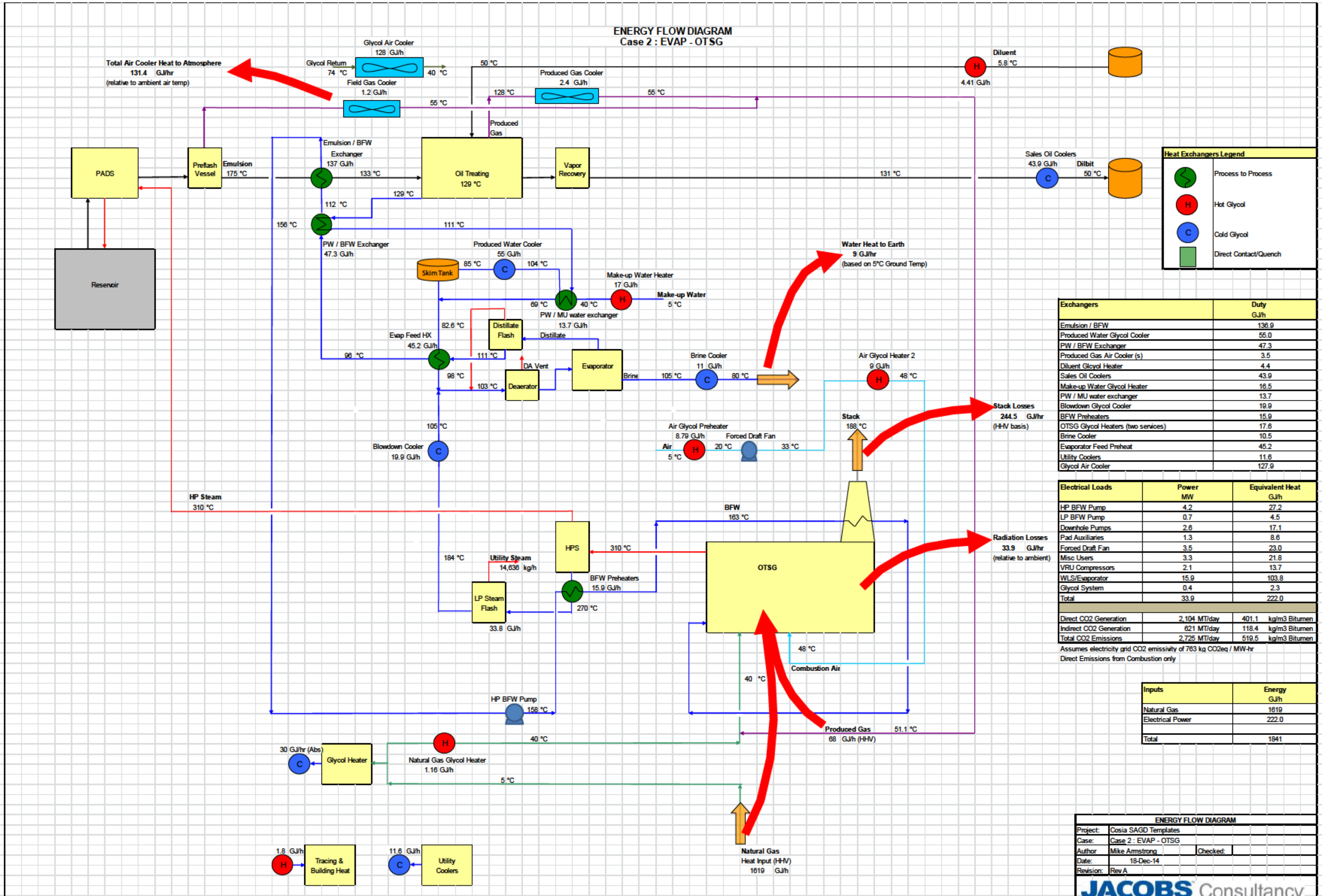
JACOBS Consultancy

Project:	Cosia SAGD Templates
Case:	Case 2 : EVAP - OTSG Rev D
Author:	Mike Armstrong
Date:	18-Dec-14

Utilities Summary

Process Unit	Capacity	Unit	Commodity	Power kW	Steam (positive=generation) HP kg/h	 LP kg/hr	Fuel Produced Gas MMSCFD	Natural Gas MMSCFD	CO2 metric t/d
Well Pads	33,000	BPD	Bitumen						
Steam Injected to Wells					-655,234				
ESP Pumps				2,619					
Auxiliaries*				1,309					
Pumpjacks									
Oil Treatment	122,948	BPD	Emulsion						
Pumps				88					
De-oiling	89,158	BPD	De-oiled Water						
Pumps				153					
VRU Compressors				2,088					
Water Treating	89,526	BPD	Produced Water						
Pumps				264					
Evaporator				15,598					
Steam Generation	17,506	m3/d CWE	Wet Steam						
Air Blower				3,516					
OTSG					727,950		1.85	35.73	2,060
Blowdown Flash						14,636			
Pumps				4,845					
Offsites									
Sulphur	0.00	metric t/d	Sulfur						
Glycol	20,373	m3/d	Glycol	354				0.81	44
Misc				3,083					
Totals				33,918					

*** Wellpad auxiliaries are assumed to be 50% of ESP power requirements**



Exchangers	Duty GJ/h
Emulsion / BFW	136.9
Produced Water Glycol Cooler	55.0
PW / BFW Exchanger	47.3
Produced Gas Air Cooler (s)	3.5
Diluent Glcyol Heater	4.4
Sales Oil Coolers	43.9
Make-up Water Glycol Heater	16.5
PW / MU water exchanger	13.7
Blowdown Glycol Cooler	19.9
BFW Preheaters	15.9
OTSG Glycol Heaters (two services)	17.6
Brine Cooler	10.5
Evaporator Feed Preheat	45.2
Utility Coolers	11.6
Glycol Air Cooler	127.9

Electrical Loads	Power MW	Equivalent Heat GJ/h
HP BFW Pump	4.2	27.2
LP BFW Pump	0.7	4.5
Downhole Pumps	2.6	17.1
Pad Auxiliaries	1.3	8.6
Forced Draft Fan	3.5	23.0
Misc Users	3.3	21.8
VRU Compressors	2.1	13.7
WLS/Evaporator	15.9	103.8
Glycol System	0.4	2.3
Total	33.9	222.0
Direct CO2 Generation	2,104 MT/day	401.1 kg/m3 Bitumen
Indirect CO2 Generation	621 MT/day	118.4 kg/m3 Bitumen
Total CO2 Emissions	2,725 MT/day	519.5 kg/m3 Bitumen

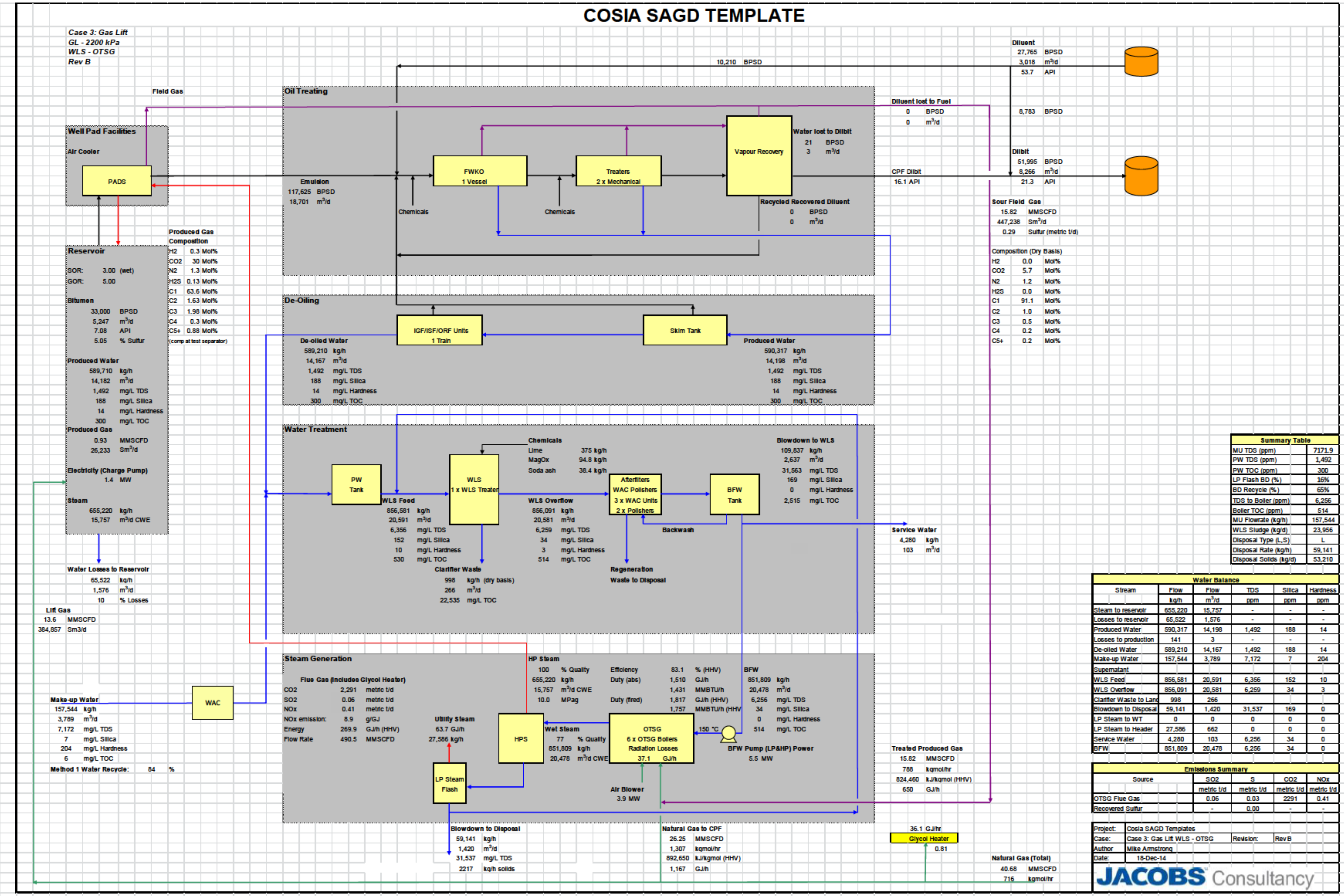
Assumes electricity grid CO2 emissivity of 763 kg CO2eq / MW-hr
Direct Emissions from Combustion only

Inputs	Energy GJ/h
Natural Gas	1619
Electrical Power	222.0
Total	1841

ENERGY FLOW DIAGRAM			
Project:	Cosia SAGD Templates		
Case:	Case 2 : EVAP - OTSG		
Author	Mike Armstrong	Checked:	
Date:	18-Dec-14		
Revision:	Rev A		

JACOBS Consultancy

12.3 CPF#3: GL-WLS-OTSG



Summary Table	
MU TDS (ppm)	7171.9
PW TDS (ppm)	1,492
PW TOC (ppm)	300
LP Flash BD (%)	16%
BD Recycle (%)	65%
TDS to Boiler (ppm)	6,256
Boiler TOC (ppm)	514
MU Flowrate (kg/h)	157,544
WLS Sludge (kg/d)	23,956
Disposal Type (L,S)	L
Disposal Rate (kg/h)	59,141
Disposal Solids (kg/d)	53,210

Water Balance					
Stream	Flow	Flow	TDS	Silica	Hardness
	kg/h	m^3/d	ppm	ppm	ppm
Steam to reservoir	655,220	15,757	-	-	-
Losses to reservoir	65,522	1,576	-	-	-
Produced Water	590,317	14,198	1,492	188	14
Losses to production	141	3	-	-	-
De-oiled Water	589,210	14,167	1,492	188	14
Make-up Water	157,544	3,789	7,172	7	204
Supernatant					
WLS Feed	856,581	20,591	6,356	152	10
WLS Overflow	856,091	20,581	6,259	34	3
Clarifier Waste to Land	998	266			
Blowdown to Disposal	59,141	1,420	31,537	169	0
LP Steam to WT	0	0	0	0	0
LP Steam to Header	27,586	662	0	0	0
Service Water	4,280	103	6,256	34	0
BFW	851,809	20,478	6,256	34	0

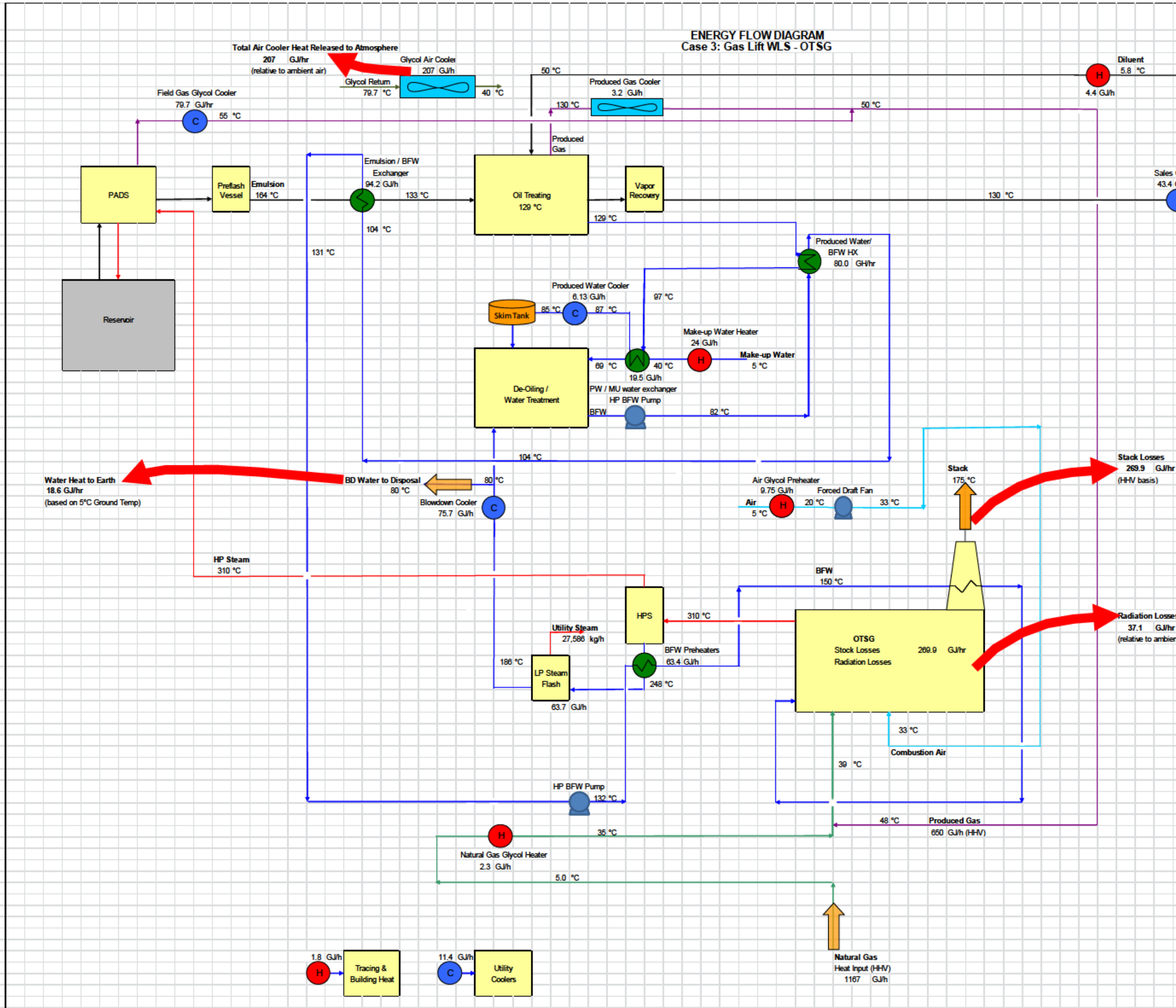
Emissions Summary				
Source	SO2	S	CO2	NOx
	metric t/d	metric t/d	metric t/d	metric t/d
OTSG Flue Gas	0.06	0.03	2291	0.41
Recovered Sulfur	-	0.00	-	-

Project:	Cosia SAGD Templates		
Case:	Case 3: Gas Lift WLS - OTSG	Revision:	Rev B
Author	Mike Armstrong		
Date:	18-Dec-14		

Project:	Cosia SAGD Templates
Case:	Case 3: Gas Lift WLS - OTSG Rev B
Author:	Mike Armstrong
Date:	18-Dec-14

Utilities Summary									
Process Unit	Capacity	Unit	Commodity	Power kW	Steam (positive=generation) HP kg/h	LP kg/hr	Fuel Produced Gas MMSCFD	Natural Gas MMSCFD	CO2 metric t/d
Well Pads	33,000	BPD	Bitumen						
Steam Injected to Wells					-655,220				
ESP Pumps				1,375					
Auxiliaries*				1,500					
Pumpjacks									
Oil Treatment	117,625	BPD	Emulsion						
Pumps				88					
De-oiling	89,105	BPD	De-oiled Water						
Pumps				153					
VRU Compressors				255					
Water Treating	89,300	BPD	Produced Water						
Pumps				54					
WLS				425					
Steam Generation	20,478	m3/d CWE	Wet Steam						
Air Blower				3,891					
OTSG					655,220	27,586	15.82	26.25	2,247
Pumps				5,481					
Offsites									
Sulphur	0.00	metric t/d	Sulfur						
Glycol	28,401	m3/d	Glycol	496				0.81	44
Misc				1,372					
Totals				15,090					

*** Auxiliaries power assumed to be 1500 KW**



Heat Exchangers Legend

- Process to Process
- Hot Glycol
- Cold Glycol
- Direct Contact/Quench

Exchangers	Duty GJ/h
Emulsion / BFW	94.2
Produced Water Glycol Cooler	6.1
PW / BFW Exchanger	80.0
Produced Gas Air Cooler (s)	3.2
Diluent Glcyol Heater	4.4
Sales Oil Coolers	43.4
Make-up Water Glycol Heater	23.5
PW / MU water exchanger	19.5
Blowdown Glycol Cooler	75.7
BFW Preheaters	63.4
OTSG Air Glycol Heater	N/A
Glycol Natural Gas Preheater	N/A
Field Gas / Glycol Cooler	79.7
Utility Coolers	11.4
Glycol Air Cooler	206.6

Electrical Loads	Power MW	Equivalent Heat GJ/h
HP BFW Pump	4.7	30.7
LP BFW Pump	0.8	5.2
Wellpad Pumps	1.4	9.0
Pad Auxiliaries	1.5	9.8
Forced Draft Fan	3.9	25.5
Misc Users	1.9	12.2
VRU Compressors	0.3	1.7
WLS/Evaporator	0.5	3.1
Glycol System	0.5	3.2
Total	15.3	100.4
Direct CO2 Generation	2,291 MT/day	436.6 kg/m3 Bitumen
Indirect CO2 Generation	281 MT/day	53.6 kg/m3 Bitumen
Total CO2 Emissions	2,572 MT/day	490.1 kg/m3 Bitumen

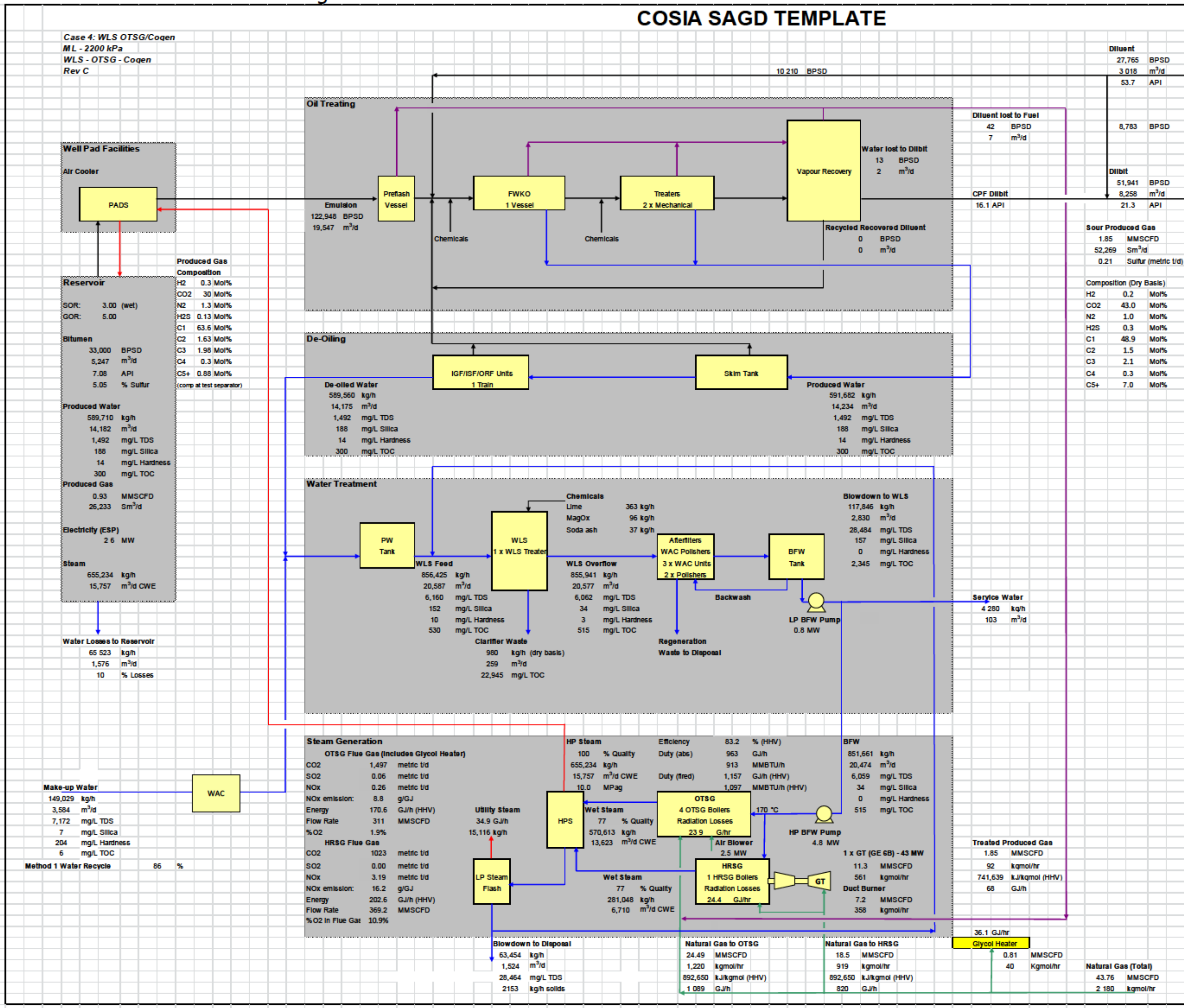
Assumes electricity grid CO2 emissivity of 763 kg CO2eq / MW-hr
Direct Emissions from Combustion only

Inputs	Energy GJ/h
Natural Gas	1167
Electrical Power	100.4
Total	1268

ENERGY FLOW DIAGRAM			
Project:	Cosia SAGD Templates		
Case:	Case 3: Gas Lift WLS - OTSG		
Author	Mike Armstrong	Checked:	
Date:	22-Aug-14		
Revision:	Rev C		

JACOBS Consultancy

12.4 CPF#4: ML-WLS-OTSG-Cogen



Summary Table	
MU TDS (ppm)	7171.9
PW TDS (ppm)	1,492
PW TOC (ppm)	300
LP Flash BD (%)	11%
BD Recycle (%)	60%
TDS to Boiler (ppm)	6,059
Boiler TOC (ppm)	515
MU Flowrate (kg/h)	149,029
WLS Sludge (kg/d)	23 530
Disposal Type (L S)	L
Disposal Rate (kg/h)	63 454
Disposal Solids (kg/d)	51,661

Water Balance					
Stream	Flow	Flow	TDS	Silica	Hardness
	kg/h	m³/d	ppm	ppm	ppm
Steam to reservoir	655,234	15,757	-	-	-
Losses to reservoir	65,523	1,576	-	-	-
Produced Water	591,682	14,234	1,492	188	14
Losses to production	85	2	-	-	-
De-oiled Water	589,560	14,175	1,492	188	14
Make-up Water	149,029	3,584	7,172	7	204
Supernatant					
WLS Feed	856,425	20,587	6,160	152	10
WLS Overflow	855,941	20,577	6,062	34	3
Clarifier Waste to Land	980	259			
Blowdown to Disposal	63,454	1,524	28,484	157	0
LP Steam to WT	0	0	0		0
LP Steam to Header	15,115,997	362,784		0	0
Service Water	4,280	103	6,059	34	0
BFW	851,661	20,474	6,059	34	0

Emissions Summary				
Source	SO2	S	CO2	NOx
	metric t/d	metric t/d	metric t/d	metric t/d
OTSG Flue Gas	0.06	0.03	2519	12.01
Recovered Sulfur	-	0.00	-	-

Project:	Cosia SAGD Templates		
Case:	Case 4: WLS OTSG/Cogen	Revision:	Rev C
Author	Mike Armstrong		
Date:	18-Dec-14		

JACOBS Consultancy

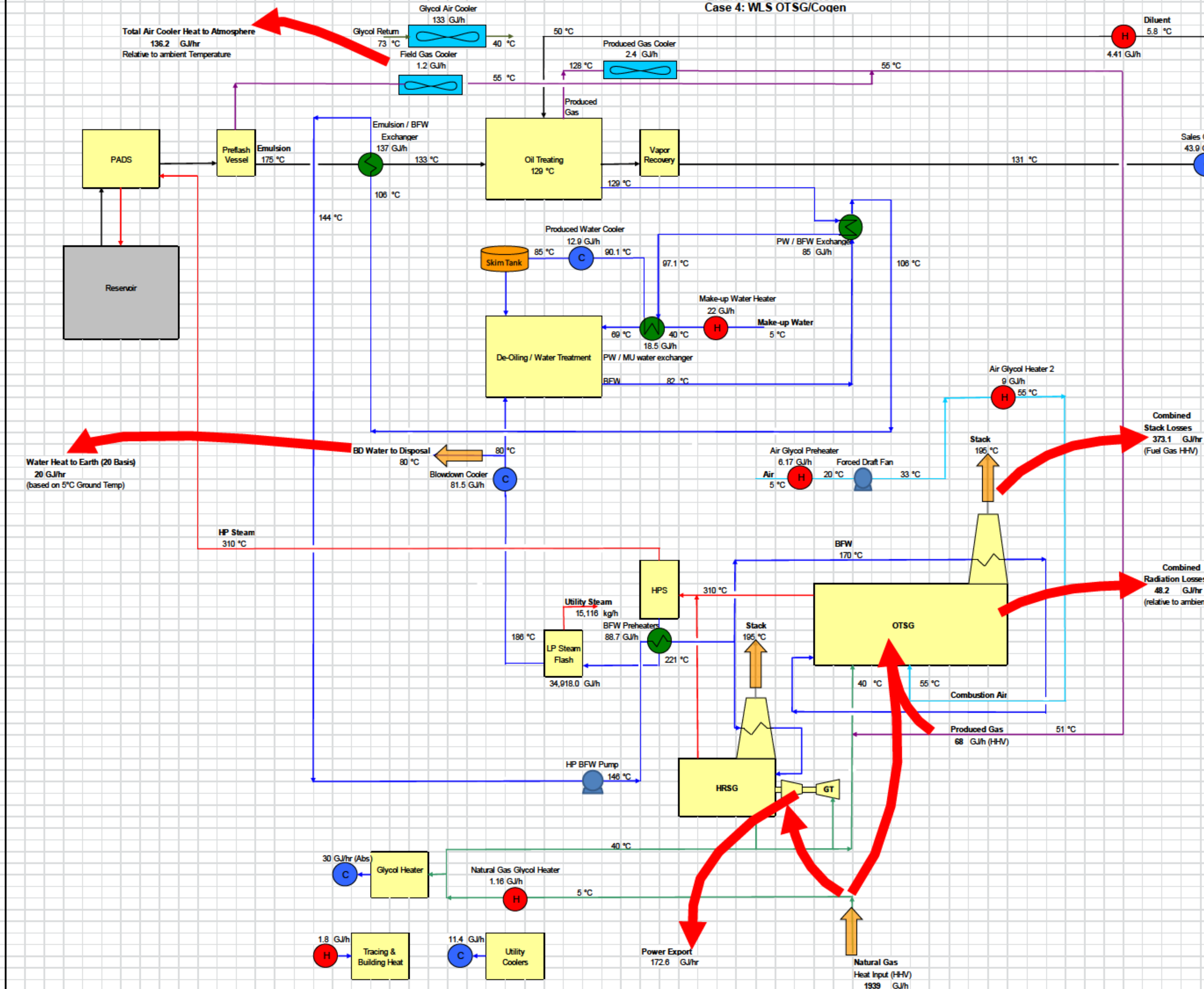
Project:	Cosia SAGD Templates
Case:	Case 4: WLS OTSG/Cogen Rev C
Author:	Mike Armstrong
Date:	18-Dec-14

Utilities Summary

Process Unit	Capacity	Unit	Commodity	Power kW	Steam (positive=generation) HP kg/h	LP kg/hr	Fuel Produced Gas MMSCFD	Natural Gas MMSCFD	CO2 metric t/d
Well Pads	33,000	BPD	Bitumen						
Steam Injected to Wells					-655,234				
ESP Pumps				2,619					
Auxiliaries*				1,309					
Pumpjacks									
Oil Treatment	122,948	BPD	Emulsion						
Pumps				88					
De-oiling	89,158	BPD	De-oiled Water						
Pumps				153					
VRU Compressors				2,087					
Water Treating	89,526	BPD	Produced Water						
Pumps				51					
WLS				425					
Steam Generation	13,623	m3/d CWE	Wet Steam						
Air Blower				2,463					
OTSG					439,007	15,116	1.85	24.49	1,453
Pumps				5,543					
Offsites									
Sulphur	0.00	metric t/d	Sulfur						
Glycol	22,006	m3/d	Glycol	382				0.81	44
Cogen	6,710	m3/d CWE	Wet Steam						
Gas Turbine				(43,000)				11.26	624
HRSG					216,227			7.19	399
Misc				1,512					
Net Power Export				**26,368**					

*** Wellpad auxiliaries are assumed to be 50% of ESP power requirements**

ENERGY FLOW DIAGRAM
Case 4: WLS OTSG/Cogen



Exchangers	Duty GJ/h
Emulsion / BFW	136.9
Produced Water Glycol Cooler	12.9
PW / BFW Exchanger	84.6
Produced Gas Air Cooler (s)	3.5
Diluent Glcyol Heater	4.4
Sales Oil Coolers	43.9
Make-up Water Glycol Heater	22.3
PW / MU water exchanger	18.5
Blowdown Glycol Cooler	81.5
BFW Preheaters	88.7
OTSG Glycol Heaters (two services)	15.3
OTSG Air Preheater (Flue Gas)	N/A
Utility Coolers	11.4
Glycol Air Cooler	132.7

Electrical Loads	Power MW	Equivalent Heat GJ/h
HP BFW Pump	4.8	31.1
LP BFW Pump	0.8	5.2
Downhole Pumps	2.6	17.1
Pad Auxiliaries	1.3	8.6
Forced Draft Fan	2.5	16.1
Misc Users	1.8	11.5
VRU Compressors	2.1	13.7
WLS/Evaporator	0.5	3.1
Glycol System	0.4	2.5
Total Demand	16.6	108.9
GT Power Generation	-43.0	-281.5
Power Export	-26.4	-172.6
Direct CO2 Generation	2,519 MT/day	480.2 kg/m3 Bitumen
Indirect CO2 Generation	-483 MT/day	-92.0 kg/m3 Bitumen
Total CO2 Emissions	2,037 MT/day	388.2 kg/m3 Bitumen

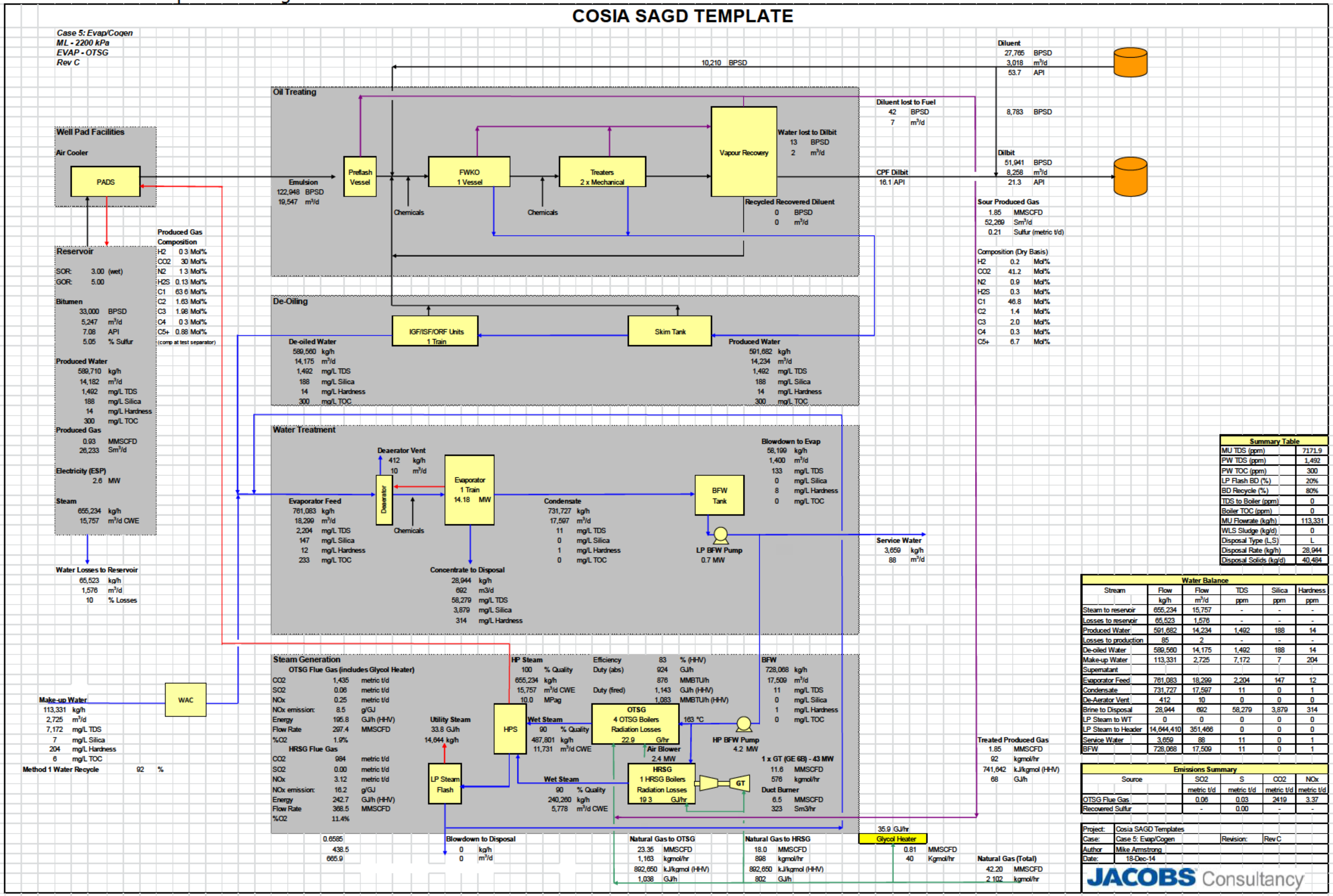
Assumes electricity grid CO_2 emissivity of 763 kg CO_2eq / MW-hr
Direct Emissions from Combustion only

Inputs	Energy GJ/h
Natural Gas	1939
Electrical Power	108.9
Total	2048

ENERGY FLOW DIAGRAM			
Project:	Cosia SAGD Templates		
Case:	Case 4: WLS OTSG/Cogen		
Author	Mike Armstrong	Checked:	
Date:	18-Dec-14		
Revision:	Rev C		

JACOBS Consultancy

12.5 CPF#5: ML-Evap-OTSG-Cogen



Summary Table	
MU TDS (ppm)	7171.9
PW TDS (ppm)	1,492
PW TOC (ppm)	300
LP Flash BD (%)	20%
BD Recycle (%)	80%
TDS to Boiler (ppm)	0
Boiler TOC (ppm)	0
MU Flowrate (kg/h)	113,331
WLS Sludge (kg/d)	0
Disposal Type (L,S)	L
Disposal Rate (kg/h)	28,944
Disposal Solids (kg/d)	40,484

Water Balance

Stream	Flow	Flow	TDS	Silica	Hardness
	kg/h	m³/d	ppm	ppm	ppm
Steam to reservoir	655,234	15,757	-	-	-
Losses to reservoir	65,523	1,576	-	-	-
Produced Water	591,682	14,234	1,492	188	14
Losses to production	85	2	-	-	-
De-oiled Water	589,560	14,175	1,492	188	14
Make-up Water	113,331	2,725	7,172	7	204
Supernatant					
Evaporator Feed	761,083	18,299	2,204	147	12
Condensate	731,727	17,597	11	0	1
De-Aerator Vent	412	10	0	0	0
Brine to Disposal	28,944	692	58,279	3,879	314
LP Steam to WT	0	0	0	0	0
LP Steam to Header	14,644,410	351,466	0	0	0
Service Water	3,659	88	11	0	1
BFW	728,068	17,509	11	0	1

Emissions Summary

Source	SO2	S	CO2	NOx
	metric t/d	metric t/d	metric t/d	metric t/d
OTSG Flue Gas	0.06	0.03	2419	3.37
Recovered Sulfur	-	0.00	-	-

Project:	Cosia SAGD Templates		
Case:	Case 5: Evap/Cogen	Revision:	Rev C
Author	Mike Armstrong		
Date:	18-Dec-14		

JACOBS Consultancy

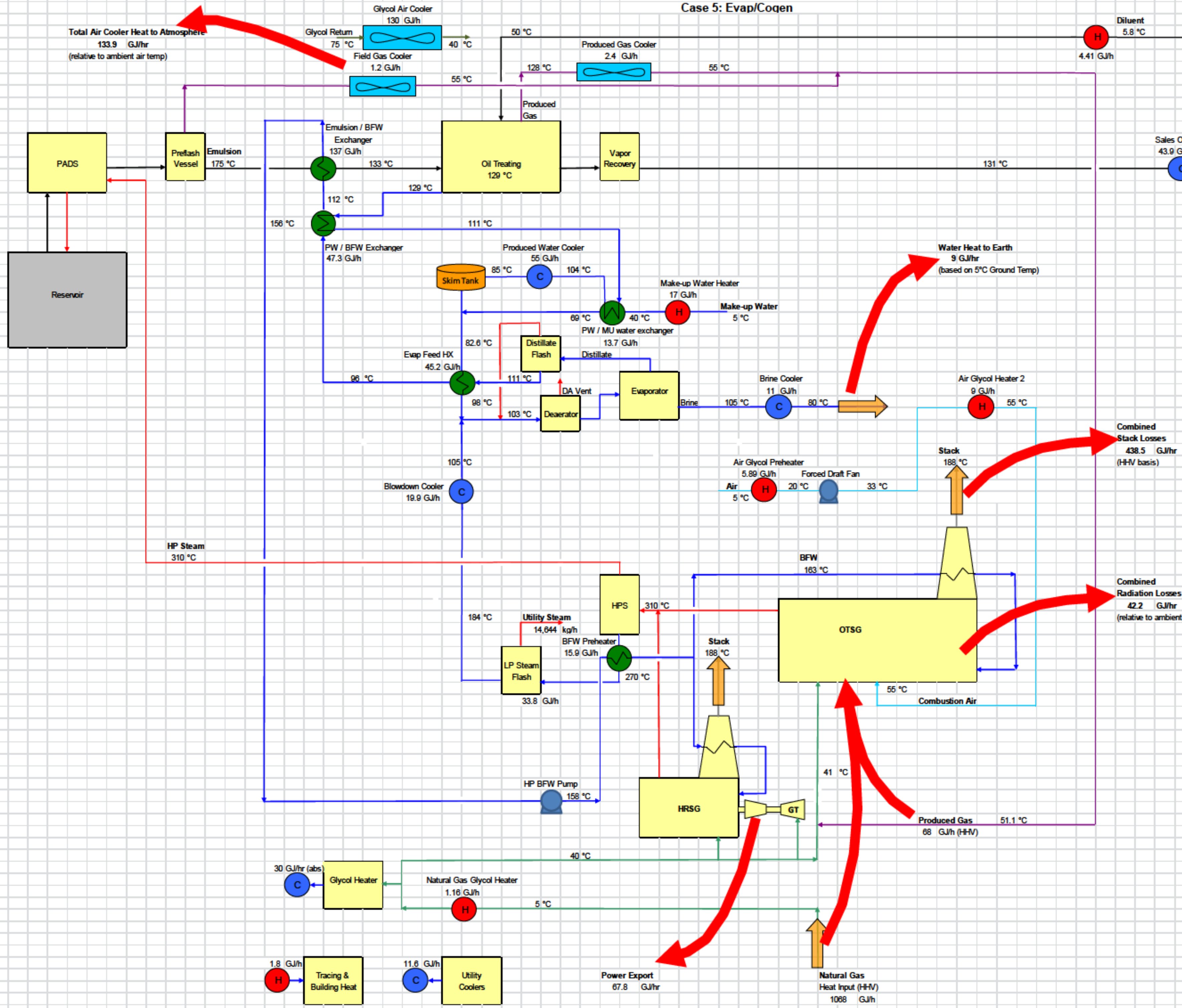
Project:	Cosia SAGD Templates
Case:	Case 5: Evap/Cogen Rev C
Author:	Mike Armstrong
Date:	18-Dec-14

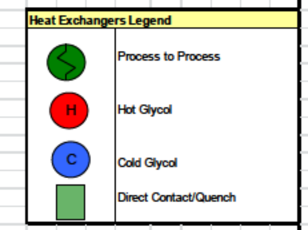
Utilities Summary

Process Unit	Capacity	Unit	Commodity	Power kW	Steam (positive=generation) HP kg/h	LP kg/hr	Fuel Produced Gas MMSCFD	Natural Gas MMSCFD	CO2 metric t/d
Well Pads	33,000	BPD	Bitumen						
Steam Injected to Wells					(655,234)				
ESP Pumps				2,619					
Auxiliaries*				1,309					
Pumpjacks									
Oil Treatment	122,948	BPD	Emulsion						
Pumps				88					
De-oiling	89,158	BPD	De-oiled Water						
Pumps				153					
VRU Compressors				2,087					
Water Treating	89,526	BPD	Produced Water						
Pumps				264					
Evaporator				15,600					
Steam Generation	11,731	m3/d CWE	Wet Steam						
Air Blower				2,356					
OTSG					439,007		1.85	23.35	1,391
Blowdown Flash						14,644			
Pumps				4,845					
Offsites									
Sulphur	0.00	metric t/d	Sulfur						
Glycol	20,371	m3/d	Glycol	354				0.81	44
Cogen	5,778	m3/d CWE	Wet Steam						
Gas Turbine				(43,000)				11.56	631
HRSG					216,227			6.48	353
Misc				2,968					
Net Power Export				**10,356**					

*** Wellpad auxiliaries are assumed to be 50% of ESP power requirements**

ENERGY FLOW DIAGRAM
Case 5: Evap/Cogen





Exchangers	Duty GJ/h
Emulsion / BFW	136.9
Produced Water Glycol Cooler	55.0
PW / BFW Exchanger	47.3
Produced Gas Air Cooler (s)	3.5
Diluent Glcyol Heater	4.4
Sales Oil Coolers	43.9
Make-up Water Glycol Heater	16.6
PW / MU water exchanger	13.7
Blowdown Glycol Cooler	19.9
BFW Preheaters	15.9
OTSG Glycol Heaters (two services)	14.6
Brine Cooler	10.6
Evaporator Feed Preheat	45.2
Utility Coolers	11.6
Glycol Air Cooler	130.3

Electrical Loads	Power MW	Equivalent Heat GJ/h
HP BFW Pump	4.2	27.2
LP BFW Pump	0.7	4.5
Downhole Pumps	2.6	17.1
Pad Auxiliaries	1.3	8.6
Forced Draft Fan	2.4	15.4
Misc Users	3.2	21.0
VRU Compressors	2.1	13.7
WLS/Evaporator	15.9	103.8
Glycol System	0.4	2.3
Total	32.6	213.7
GT Power Generation	-43.0	-281.5
Power Export	-10.4	-67.8
Direct CO2 Generation	2,419 MT/day	461.1 kg/m3 Bitumen
Indirect CO2 Generation	-190 MT/day	-36.1 kg/m3 Bitumen
Total CO2 Emissions	2,229 MT/day	424.9 kg/m3 Bitumen

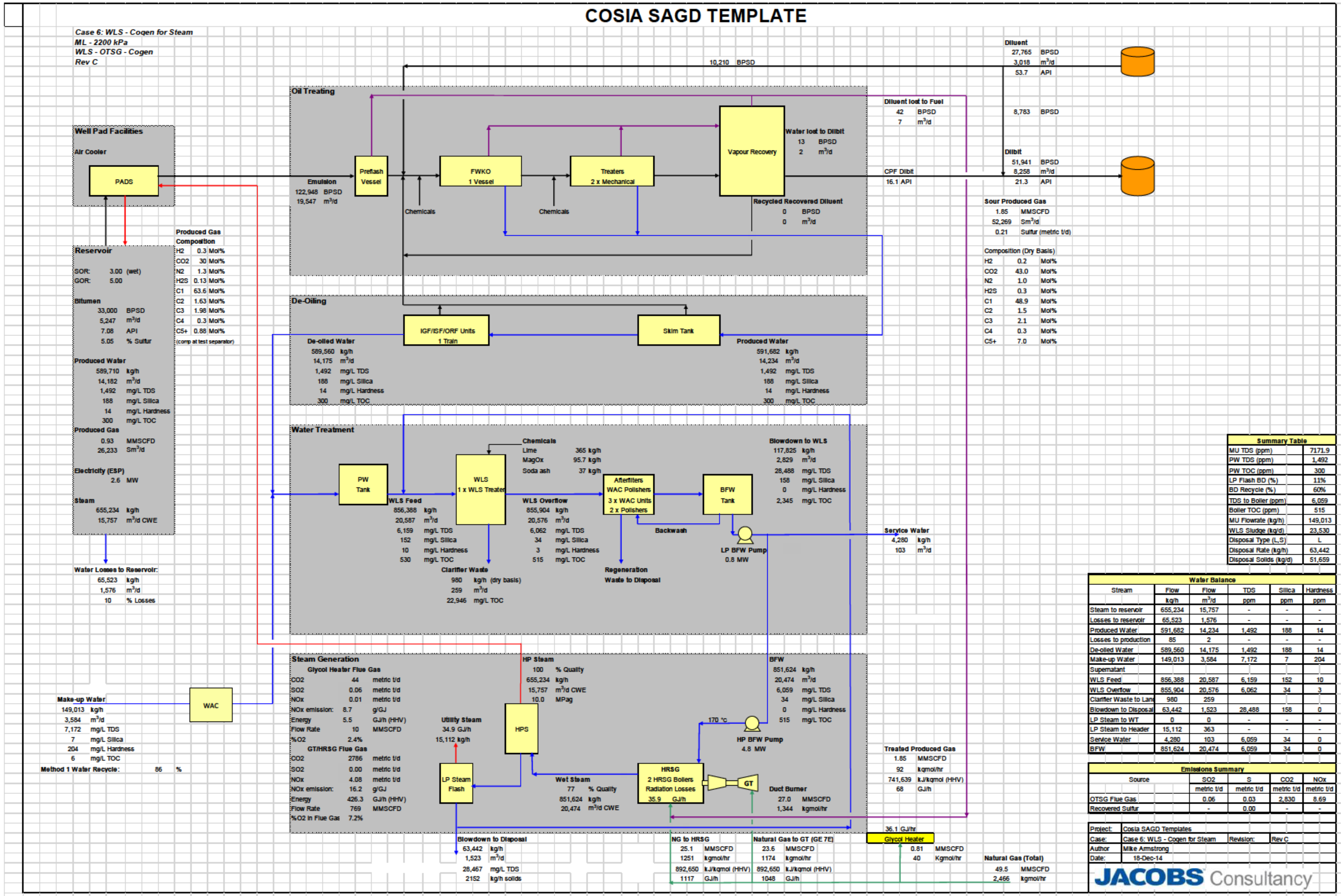
Assumes electricity grid CO2 emissivity of 763 kg CO2eq / MW-hr
Direct Emissions from Combustion only

Inputs	Energy GJ/h
Natural Gas	1068
Electrical Power	213.7
Total	1282

ENERGY FLOW DIAGRAM			
Project:	Cosia SAGD Templates		
Case:	Case 5: Evap/Cogen		
Author	Mike Armstrong	Checked:	
Date:	18-Dec-14		
Revision:	Rev C		

JACOBS Consultancy

12.6 CPF#6: ML-WLS-Cogen



Summary Table	
MU TDS (ppm)	7171.9
PW TDS (ppm)	1,492
PW TOC (ppm)	300
LP Flash BD (%)	11%
BD Recycle (%)	60%
TDS to Boiler (ppm)	6,059
Boiler TOC (ppm)	515
MU Flowrate (kg/h)	149,013
WLS Sludge (kg/d)	23,530
Disposal Type (L,S)	L
Disposal Rate (kg/h)	63,442
Disposal Solids (kg/d)	51,659

Water Balance					
Stream	Flow	Flow	TDS	Silica	Hardness
	kg/h	m^3/d	ppm	ppm	ppm
Steam to reservoir	655,234	15,757	-	-	-
Losses to reservoir	65,523	1,576	-	-	-
Produced Water	591,682	14,234	1,492	188	14
Losses to production	85	2	-	-	-
De-oiled Water	589,560	14,175	1,492	188	14
Make-up Water	149,013	3,584	7,172	7	204
Supernatant					
WLS Feed	856,388	20,587	6,159	152	10
WLS Overflow	855,904	20,576	6,062	34	3
Clarifier Waste to Lan	980	259			
Blowdown to Disposal	63,442	1,523	28,488	158	0
LP Steam to WT	0	0	-	-	-
LP Steam to Header	15,112	363	-	-	-
Service Water	4,280	103	6,059	34	0
BFW	851,624	20,474	6,059	34	0

Emissions Summary				
Source	SO2	S	CO2	NOx
	metric t/d	metric t/d	metric t/d	metric t/d
OTSG Flue Gas	0.06	0.03	2,830	8.69
Recovered Sulfur	-	0.00	-	-

Project:	Cosia SAGD Templates		
Case:	Case 6: WLS - Cogen for Steam	Revision:	Rev C
Author	Mike Armstrong		
Date:	18-Dec-14		

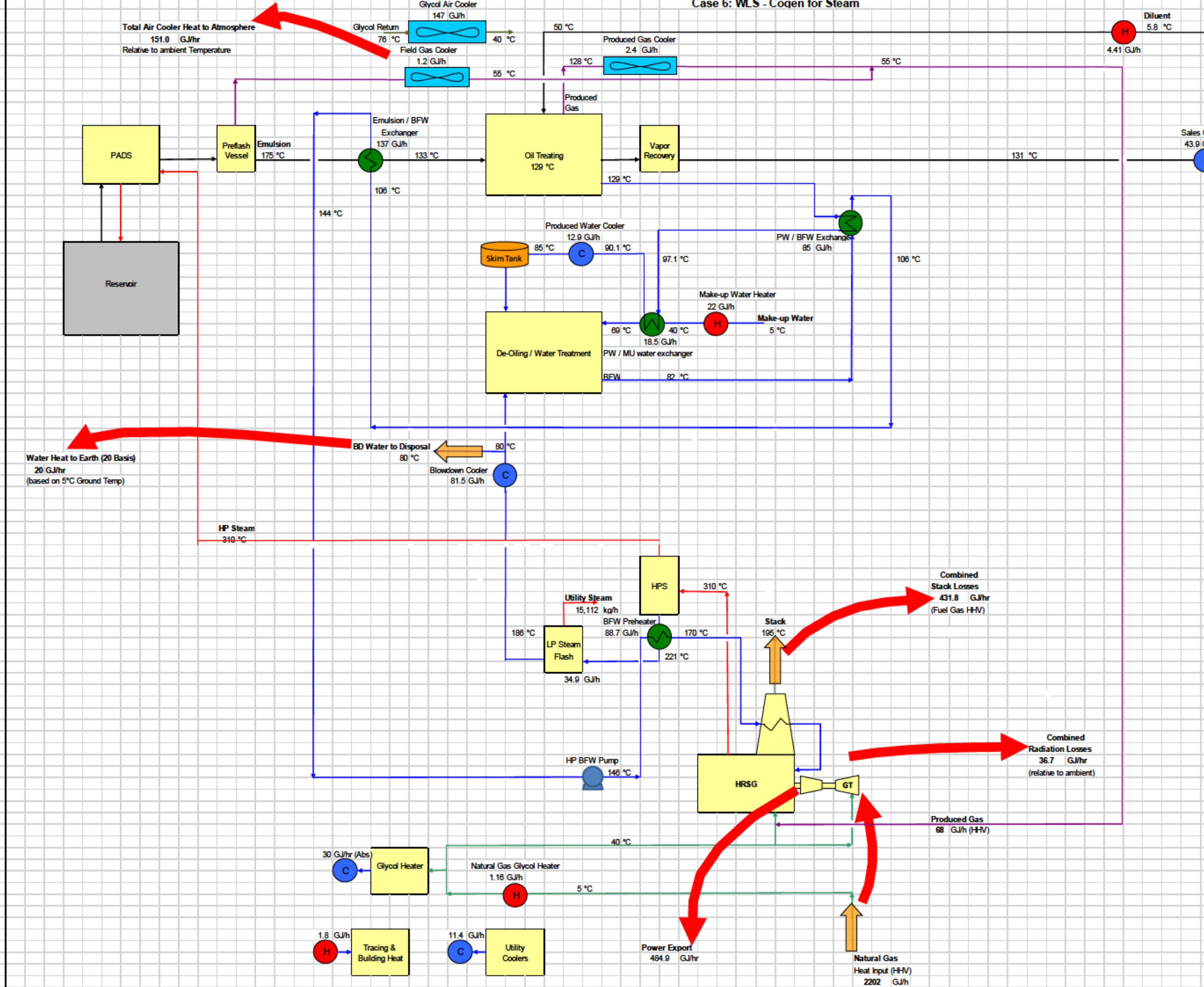
Project:	Cosia SAGD Templates
Case:	Case 6: WLS - Cogen for Steam Rev C
Author:	Mike Armstrong
Date:	18-Dec-14

Utilities Summary

Process Unit	Capacity	Unit	Commodity	Power kW	Steam (positive=generation) HP kg/h	LP kg/hr	Fuel Produced Gas MMSCFD	Natural Gas MMSCFD	CO2 metric t/d
Well Pads	33,000	BPD	Bitumen						
Steam Injected to Wells					-655,234				
ESP Pumps				2,619					
Auxiliaries*				1,309					
Pumpjacks									
Oil Treatment	122,948	BPD	Emulsion						
Pumps				88					
De-oiling	89,158	BPD	De-oiled Water						
Pumps				153					
VRU Compressors				2,087					
Water Treating	89,526	BPD	Produced Water						
Pumps				51					
WLS				425					
Steam Generation	0	m3/d CWE	Wet Steam						
Air Blower									
OTSG						15,111,565			
Pumps				5,543					
Offsites									
Sulphur	0.00	metric t/d	Sulfur						
Glycol	22,005	m3/d	Glycol	383				0.81	44
Cogen	20,474	m3/d CWE	Wet Steam						
Gas Turbine				-88,000				23.58	1,299
HRSG					655,234		1.85	26.98	1,486
Misc				1,266					
Net Power Export				**74,076**					

*** Wellpad auxiliaries are assumed to be 50% of ESP power requirements**

ENERGY FLOW DIAGRAM
Case 6: WLS - Cogen for Steam



Exchangers	Duty GJ/h
Emulsion / BFW	136.9
Produced Water Glycol Cooler	12.9
PW / BFW Exchanger	84.6
Produced Gas Air Cooler (s)	2.4
Diluent Glcyol Heater	4.4
Sales Oil Coolers	43.9
Make-up Water Glycol Heater	22.3
PW / MU water exchanger	18.5
Blowdown Glycol Cooler	81.5
BFW Preheaters	88.7
OTSG Glycol Air Preheaters (two services)	N/A
OTSG Air Preheater (Flue Gas)	N/A
Utility Coolers	11.4
Glycol Air Cooler	147.5

Electrical Loads	Power MW	Equivalent Heat GJ/h
HP BFW Pump	4.8	31.1
LP BFW Pump	0.8	5.2
Downhole Pumps	2.6	17.1
Pad Auxiliaries	1.3	8.6
Forced Draft Fan	0.0	0.0
Misc Users	1.5	9.9
VRU Compressors	2.1	13.7
WLS/Evaporator	0.5	3.1
Glycol System	0.4	2.5
Total Demand	13.9	91.1
GT Power Generation	-88.0	-576.0
Power Export	-74.1	-484.9
Direct CO2 Generation	2,830 MT/day	539.3 kg/m3 Bitumen
Indirect CO2 Generation	-1356 MT/day	-258.5 kg/m3 Bitumen
Total CO2 Emissions	1,473 MT/day	280.8 kg/m3 Bitumen

Assumes electricity grid CO2 emissivity of 763 kg CO2eq / MW-hr

Direct Emissions from Combustion only

Inputs	Energy GJ/h
Natural Gas	2202
Electrical Power	91.1
Total	2293

ENERGY FLOW DIAGRAM			
Project:	Cosia SAGD Templates		
Case:	Case 6: WLS - Cogen for Steam		
Author	Mike Armstrong	Checked:	
Date:	18-Dec-14		
Revision:	Rev A		

JACOBS Consultancy