BIOGRAPHY

Cameron Todd

Connacher Oil and Gas Company Limited

Cameron Todd is currently Vice President Refining and Marketing for Connacher Oil and Gas Limited. Cameron is responsible for downstream operations including operation of the company’s 10,000 BPD heavy oil refinery in Great Falls, Montana, the blending and sale of bitumen production from the company’s 10,000 BPD Great Divide SAGD project, located south of Ft McMurray, Alberta, the procurement and transportation of diluent and the marketing of the company’s conventional oil and gas production.

Cameron has worked for over 29 years in the oil and gas industry, and has held various executive, management, operational and engineering positions with companies in Alberta, the US and Argentina. Cam’s first experience with diluent and heavy oil, goes back to 1984 when he worked on development of Amoco’s Elk Point project and later on the company’s Primrose project. He is the author of a number of papers and studies on heavy oil, bitumen, upgrading, diluent and transportation.

Cameron graduated from the University of Calgary in 1980 with a BSc in Mechanical Engineering. He lives in Calgary, is married and has four children.

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Diluent and Bitumen, An Uneasy Mix
Considerations for treating, blending, transportation, marketing and refining

Cameron M. Todd
Connacher Oil and Gas Limited

Condensates and gasolines are commonly used to dilute heavier and more viscous crude oils in order to improve field processing, transportability in pipelines and acceptability in markets and refineries. The large amount of heavy oil and bitumen currently produced in Canada and projected for the future has resulted in a large demand for such diluent, and attractive prices have resulted. Consequently a wide range of diluent sources, quality and components are finding their way into the Canadian diluent supply stream, with attendant concerns arising regarding diluent performance and impact upon resulting blended crude oil. The cost of diluent is one of the largest controllable expenses associated with most bitumen production projects. This paper assesses a number of the issues associated with the use of diluent as a blending agent with Canadian bitumen. Issues to be considered include market factors such as supply, demand, price and infrastructure, operational processing and blending issues, diluent quality and component variability, and downstream issues including refinery processing and yields.
Diluent and Bitumen – An Uneasy Mix

A Presentation by Cameron Todd, VP Refining and Marketing
to the 5th NCUT Upgrading and Refining Conference

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Keeping our ducks in a row
This presentation contains forward looking information including expectations of future production and bitumen production goals including the anticipated timing associated therewith, the role of diluent in bitumen operations, estimates of supply of natural gas condensates, future diluent requirements, density equalizations and what constitutes the best diluent for use in blending with bitumen including associated economics. Forward looking information is based on management’s expectations regarding future growth and take into account expectations regarding operating costs, average realized oil and natural gas prices, average throughput, costs of purchased feedstock, steam:oil ratios, results of operation, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), plans for and results of drilling activity, environmental matters, business prospects and opportunities, future royalty rates, commodity prices and foreign exchange rates and future economic conditions and involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: the risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; actual steam:oil ratios being different than what was anticipated; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), the risk of commodity price and foreign exchange rate fluctuations, risks related to future royalty rate changes and risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the continued expansion of the Great Divide Project at Algar and other regions and expansion of the company’s conventional and refinery operations. In addition, the current financial crisis has resulted in severe economic uncertainty and resulting illiquidity in credit and capital markets which increases the risk that actual results will vary from forward looking expectations and these variations may be material. These risks and uncertainties are described in detail in Connacher’s Annual Information Form for the year ended December 31, 2008, which is available at www.sedar.com. Certain assumptions relating to reserves and resources and the future net revenue associated therewith are contained in Connacher’s Annual Information Form. Certain assumptions relating to estimated future operating margins and netbacks are included in the notes to slides 16 and 38. The Corporation assumes no obligation to update or revise the forward-looking information to reflect new events or circumstances, except as required by law. All references to barrels of oil equivalent (boe) are calculated on the basis of 6 Mcf : 1 bbl (unless otherwise indicated). This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation.

This paper represents solely the opinions and conclusions of the author which may not agree with those of Connacher
Uneasy Mix Outline

• Introduction
• Diluent - what is it good for?
• Will there be enough diluent?
• Where does diluent come from?
• What about quality – Does it matter what we mix with our bitumen?
• How much does it cost – is it economic?
• What diluent is best?
• Conclusions
Who is Connacher?

• **Small integrated oil sands producer/developer**
  – Great Divide Project (Athabasca)
    • 10,000 BPD SAGD
    • Currently 8,000 BPD bitumen production
  – Algar Project
    • 10,000 BPD SAGD
    • Under construction, 2010 startup

• **Fully integrated company**
  – SAGD oil sands production
  – Natural gas production
  – Refinery – 10,000 BPD Great Falls, Montana
  – Diluent producer

• **Great Divide**
  – Treat bitumen with diluent
  – Purchase diluent
    • Refinery naphtha
    • Condensate
  – Truck dilbit to market
  – Rail and truck transport
  – Pursuing pipeline connection
What is the Role of Diluent in Heavy Oil/Bitumen Operations?

- Dilute heavy oil / bitumen to:
  - Reduce viscosity
  - Reduce TAN (Total Acid Number)
  - Reduce sulphur / heavy metals
  - Reduce density
- Aid in de-watering and treating
- Removal of non-hydrocarbon solids (clay and fines)
- Extraction and upgrading (froth treatment, asphaltene removal)
- Future - next generation solvent SAGD
- Historically the dilution function has largely been a volume function (i.e., volumetric dilution)
- Increasingly chemistry has been of interest / concern
Treating Challenges for the SAGD Operator

- SAGD Operations produce tight emulsions
- Primarily oil-in-water
- But also water –in-oil (simultaneously)
  - Also micro-emulsion
- Tight emulsions (high interfacial tension)
  - Steam injected at high temperature and pressure “collapses” into water drawing in bitumen and forming emulsions in-situ
  - Additional shearing occurs in reservoir, flow through liner slots, downhole pumps and during pressure reduction at surface
  - Emulsions are very stable
  - Emulsifying agents may include clays, dissolved silica and other minerals as well as complex components in bitumen

Figure 9a – Top layer O/W emulsions of batch 2 (B2S2). Circles are oil droplets in water
Bitumen and Water Treating Challenges

- Water separation is very difficult, must be < .5% BSW
  - Very tight emulsions are formed
  - Athabasca bitumen heavier than water, but close to water density
  - Heating changes density but difference not enough unless very hot
  - Tiny difference in electric potential (zeta)
  - Add diluent to “lighten” the crude, improve separation
  - Modify PH and add demulsifiers
- Diluent and chemicals must work together
- High water recycle (95%) means no oil residue is allowed
  - Water in oil emulsion/micro-emulsion is a problem
- Solids build-up in treater can be a problem
  - Sand and clay in most operations, not at Connacher
  - Possibly due to precipitation of asphaltene film in water-in-oil emulsion
- Light ends of diluent flash off in sales tanks (diluent losses and VRU loading)
Will there be enough diluent?

- Alberta ran out of sufficient natural gas condensate to meet local demand for diluent long ago
  - Natural gas condensate is in decline
  - Bitumen production is steadily increasing
  - Every 100,000 bpd of bitumen produced will require 35-40,000 bpd of additional diluent (excluding upgraded bitumen and synthetic diluent)
  - We now rely on imported diluent to balance the supply
  - US and offshore diluent supply is increasing and sufficient
    - Southern Lights will bring diluent in 2010 (up to 180,000 bpd)
  - Diluent recycle may be an efficient solution

- Since diluent is broadly defined as hydrocarbon liquid between 600 to 800 kg/m3 density (API 45 to 105⁰) a wide range of diluents is used
  - Natural gas plant condensate
  - Refinery naphtha’s and light gasoline blend stocks
  - Other blended hydrocarbons

- Many transportation means are used to supply diluent
  - Pipeline, truck, rail, ship
  - Transportation and storage logistics are challenging
Diluent – Where does it come from?

- Diluent is a light hydrocarbon with density between 600-800 kg/m3
- Natural gas condensate comes from processing natural gas, much from Alberta production, collected from gas plants and shipped by pipeline, truck and rail
- Natural gas condensate is also produced with LNG, then is shipped to N. America by tanker
- Condensate produced from solution gas plants is “richer” and contains small amounts of heavier components
- Refinery straight run gasoline, light and heavy naphtha's and distillates are produced by distilling crude oils at refineries. They may contain more aromatic components which are generally desirable blending agents. US refineries have excess capacity for export.
- Reformulated or alkylated gasoline blending stocks are generally expensive but may be used as diluent when gasoline is in short supply
- Cracked refinery or upgrader products such as cracked gasoline, distillates or coker products may be “under-saturated” and less stable. They may contain olefins and other components which may work as diluents but be less desirable to refiners downstream
- Light crude oils may fall into acceptable density range for blending but may cause concern with asphaltene precipitation and are not desirable as diluent
- LPG’s in small amounts may be blended with heavier hydrocarbons (such as light oils) with the blended product used as diluent. For most heavy producers this is not desirable. Light ends flash off and may cause asphaltene precipitation.
Natural Gas Plant Condensate

- Condensate comes from natural gas which in its natural reservoir state is in a gaseous form
- Condenses out of gas with reduction in pressure and/or temperature
- Separated at gas plants and fractionation facilities primarily by chilling
- Gas is primarily methane with progressively smaller amounts of C2, C3 and heavier components
- Condensate is mostly C5 with lesser amounts of heavier components; mostly simple straight chain paraffins
- Historically condensates have required additional processing to make useful products
  - Petrochemicals
  - Gasoline (too low octane number)
- Today diluent is easier (no processing) and higher value
Gas Plant Condensate Composition (Mol %)
Refinery Condensate/Naphtha and Products

- Refinery condensates/naphthas are distilled from crude oil
  - In natural state in the reservoir they are liquid
  - Separated between distillation “cut points”
  - They are a complex mix of liquid hydrocarbons which can include dozens or hundreds of different molecules
  - Can include non-naturally occurring cracked hydrocarbons
  - Aromatics, cyclo-hydrocarbons
  - Compatibility
Diluent Quality Considerations

- Broad range of diluent sources, broad specifications and premium diluent prices create potpourri of diluent characteristics
- Great incentive to make diluent for volumetric purposes and little control over chemistry
- Blending economics may result in undesirable blend stock such as LPG’s, light oils, cracked products and some upgraded products
- Suppliers to general “pool” will not be familiar with end customer (producer) needs
- Concerns with contaminants and solids

Solids found in diluent strainer prior to treating train
Diluent Blending Economics 101

Diluent Volume

- Assume we blend to 930 kg/m3 density (API 20.7) to make pipeline specs

- Assume we start with 8 API (1014 kg/m3) Athabasca bitumen and 65 API condensate (720 kg/m3)

- Blend ratio is % bitumen in the blend

- Required ratio is 71.4% bitumen and 28.6% condensate

- If we use 86 API condensate (650 kg/m3) then the required diluent is less (77% bitumen and 23% condensate)
Diluent Blending Economics 101

Diluent Cost

- Not all of the cost of diluent purchased is a loss. Diluent blended increases the volume of blend crude sold. It is however sold at a lower price.

- Net cost of diluent used is a function of price paid for diluent (premium over light sweet crude) and the price received for blended heavy crude (discount from light sweet crude)

- Net Cost per barrel bitumen = volume of diluent times (price of diluent minus price of dilbit)

- If diluent premium is $5/bbl and heavy oil discount is $20/bbl (assuming a $70/bbl WTI price) and blend ratio is 71% bitumen to 29% diluent as in previous example then net diluent cost is .29/.71*(75-50) or $10.21/bbl bitumen

- For the same condensate price using lighter diluent with the ratio 77% bitumen to 23% diluent the net cost is $7.46/bbl

- Pipeline equalization will recover some compensation (approximately $.75/bbl) but economics lean to lighter diluent (lighter gravity diluent is better!)
Density Equalization - Explained

- The market basis for density equalization currently stands at 750.0 kg/m³.
- Anything of a higher density will receive additional value and anything of a lower density will be penalized.
- Using June as the equalization basis, we can therefore calculate that;
  - a condensate with a density of 700.0 kg/m³ will be valued at C$3.50 more than the market basis
  - a condensate with a density of 800.0 kg/m³ will be penalized by C$3.50
So what is the best diluent?

- The best diluent is no diluent – less is more
- Every operation is unique – one size does not fit all
  - Special needs may require special diluents
- Light diluents allow reduced diluent blending volume
- Minimize light components to reduce diluent losses and precipitation risks (no c3 or c4 at all!)
- Aromatics increase blending compatibility and reduce precipitation risks
- Oils and heavy components offer little value and increased risk of solids precipitation – should be restricted from diluent pool
- Cracked components, benzene and contaminants may be of significant concern to refiner customers, should be segregated
Conclusions from a SAGD Producer’s Perspective

- Diluent is a scarce commodity; must be imported to ensure sufficient supply
- Diluent is the highest single cost a SAGD operator faces – minimizing diluent use is a high priority
- Challenging bitumen treating problems require careful assessment and analysis of bitumen and diluent chemistry – consider the “system" not just the pipeline requirements
- Diluent is not just a volumetric component, other physical and chemical properties are critical
- Diluent quality issues are a key concern in optimizing and ensuring stable operations
- Special needs may require segregated supplies, on-site diluent treating, recycle and dedicated transportation
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I have relied on a number of individuals and organizations with a great deal of expertise on the subjects presented here most of which have far greater experience in the area than myself. I appreciate the work they have done and would refer you to them. In addition I would like to acknowledge a number of the pictures included herein from Dr. Chandra Angle and Canmet Energy.

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