Oil and Gas Primer: Macro

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Welcome to Global Oil and Natural Gas Markets

Crude Oil

Oil is a different commodity: It has real decline curves; multiple capex cycles; Opec and other political drivers; and its demand is inelastic in the ‘short run’ – thus oil markets tend to frustrate forecasters

**Supply:** Overview of where current production comes from, some of the bright spots – e.g. the shale revolution and some of the challenges (decline, complexity and political instability)

**Demand:** Emerging markets drive the bus over the longer term, but OECD cycles still matter as well

After the **fourth oil shock, markets** now have to do the **rebalancing.** Currently, oil supply needs to come down

– “Call on US Shale”: We look in detail at the potential and economics of shale; and feature a “super-contango” story

Natural Gas

In the US, shale has unlocked 100 years of low cost natural gas

We look at the **cost curve** and discuss bottlenecks getting low cost Marcellus/Utica gas to demand centers in the south, **LNG exports**, and **rising base-load demand** from power generators and industry

**LNG:** Links regions and price (mostly to oil). Its demand should grow, but new supply options are on the horizon and the US is coming to the party

Longer Term

We can plot the end of the “oil age” albeit really only from the demand side -- some combination of natural gas substitution, energy efficiency and breakthrough technology (solar/battery) should do it
Oil -- Deciphering Its Fundamentals and Markets; Supply
What are Oil and Natural Gas?

- Oil and natural gas (or hydrocarbons) are composed of chains of linked hydrogen and carbon atoms.
- Plant and animal remains were covered by layers of sediment (particles of rock and mineral) and over millions of years of extreme pressure and temperatures these particles were reduced to liquid hydrocarbons (oil) or gaseous hydrocarbons (natural gas).
- Under geologic pressure, oil migrates from its “source rock” into rocks with larger spaces or pores “reservoir rock.” Limestone and sandstone have with large porosity and are two common types of “reservoir rock.” Oil is held in these reservoirs by impervious rock structures above called caps or traps.
Crude Oil Composition and Value Varies

- Crude oil ranges from almost clear water-like fluids to black viscous semi-solids.
- Crude oil can be categorized into various API degrees of gravity. The higher the API gravity, the lighter the crude.
- Crude oils with **higher API gravity** yield greater proportions of lighter petroleum products like gasoline.
- Crude oils with higher than average sulfur content are known as “sour.” Those with low sulfur levels are called “sweet.”
- The majority of global reserves are light/medium and slightly sour.

Source: DOE
What is So Special about Oil Fundamentals and Markets?
The supply side features politics, depletion and pushing at frontiers

Themes:

- **Reserve distribution:** Opec controls access to the low end of the cost curve and remains far and away the largest exporter of oil.
  - Its volume policy used to matter greatly, it was the balancer of last resort, stabilizer of price
  - Its current a volume maximising strategy means that the group has become a wildcard

- **Depletion:** Each year, the existing productive capacity declines by 4MBD, which needs to be offset by new investments

- Some major non-Opec sources of supply have **restricted access** or otherwise kept production on a tight leash

- **Costs** have been rising in the areas where access to resources is more open (e.g. deepwater)
  - While costs will deflate cyclically, to deliver structurally better project management is a challenge

- **New:** The (US) Shale Revolution: aka the instigator of the fourth oil shock
  - A whole new play and a the near term balancer or fly-wheel of the supply side
Oil Supply: Digging thematically -- general observations

The characteristics of producing basins vary substantially around the world, including differences in the costs of finding, development and production.

- The **United States** is the main beneficiary of the *shale revolution*. Its oil production has been rising rapidly. Potential is still only partly understood, ultimate capacity ceiling is function of price mostly. It is costly and its capital cycle is short.
  
  In today’s low price world, US shale is the marginal supply.

- The **Middle East** is the *most productive region* with the largest remaining undeveloped resources.

- **Russia** is the world’s *third largest oil producer*, much of which flows from two highly mature provinces: **Western Siberia** and **Volga/Urals**. Shale and Arctic are the growth areas to offset base declines.

- **West Africa** is a large source of production with *future growth from the offshore, if price allows*.

- **Brazil** looks like a *huge new resource opportunity* with the development of the *pre-salt play* in the offshore **Santos Basin**, but much of the near term growth profile depends on **Brasilia**.

- **Frontier areas**: Global shale, Arctic, pre-salt Angola, Equatorial Transform Margin, Eastern Siberia, even deeper Offshore
Global Oil Reserve Life or R/P Ratio 55 years …

Or, another six decades left to find an alternative transport fuel

Reserve Life or R/P Ratio measures year end reserves divided by current production

The regions with the longest R/P ratio include South and Central America (notably Venezuela and Brazil) and the Middle East, and North America is rising fast

Source: BP Stats
The majority of the world’s current proved oil reserves are in OPEC countries.

The BP Statistical Energy Review states that 1,214 billion barrels (bbs) or 71.9% of the world’s proved reserves are held by OPEC. 800 billion of these are in the Middle East.

The remaining 474 billion barrels or 28% of the world’s proved reserves are in non-OPEC regions. The former Soviet Union holds 28% of non-OPEC proved reserves. The Canadian oil sands contain 167.8 bbs of proved reserves. US oil reserves have grown by 56% to 44 bbs from a low of 28 bbs in 2008.

Source: BP Stats
OPEC has Frequently Played a Critical Price-setting Role

The Organization of Petroleum Exporting Countries (OPEC, Opec)
is a permanent, intergovernmental organization, created in 1960 by Iran, Iraq, Kuwait, Saudi Arabia, and Venezuela.

- The five Founding Members were joined by Qatar (1961); Indonesia (1962, left in 2008); Libya (1962); United Arab Emirates (1967); Algeria (1969); Nigeria (1971); Ecuador (1973 suspended membership from 1992-2007); Angola (joined in 2007), and Gabon (1975, left in 1994).

OPEC’s stated objective is “to coordinate and unify petroleum policies among Member Countries, in order to secure fair and stable prices for petroleum producers; an efficient, economic and regular supply of petroleum to consuming nations; and a fair return on capital to those investing in the industry.”

OPEC’s members in effect attempt to raise the clearing price of crude oil above its “natural” level by withholding relatively cheap reserves from the market.

- Opec grabbed pricing power (the first Oil Shock) after several of its bigger (Arab) members staged a successful boycott of oil exports to the US and a few other supporting countries that had picked the side of Israel during the Yom Kippur war of 1973

- A five-fold increase of oil prices was followed by the nationalization of oil firms in key Opec countries in the mid-1970s and after a second oil crisis surrounding the Iranian revolution of 1979, oil prices tripled to $32/b

- To sustain these massively inflated prices the group adopted a complex system of quotas, with varying degrees of success in either agreeing to them or complying with them
  - The system crashed in 1985 (the Second Oil Shock); in 1998 (the Third Oil Shock) and most recently during the American Thanksgiving holiday of 2014 (the Fourth Oil Shock)
OPEC Remains Wild Card – Even in a “Go Stabilize Yourself World”

Oil exporters probably did not think markets would react badly when Saudi Arabia withdrew control of the supply side in late 2014. Many want to renew interventionist policy, but few have leverage. And Saudi Arabia clearly remains persuaded that markets should “…stabilize themselves”, so as to weed out weak producers. The question now is: ‘What might persuade the Kingdom to sanction an intervention’?

Put differently, until Saudi Arabia says ‘yes’, the noise about an emergency OPEC is just that, noise.

The question is political. When will the pressure from constituents in the kingdom or pressure from other producers sway the Saudi top?

Financially, the kingdom appears in good shape: it built up reserves of about $750 billion; its sovereign debt is a measly 3% of GDP; and best estimates of its current requirements suggests it could last ~5 years if Brent = $65/b. That said, in April 2015 its ‘cash-burn’ was $16 billion.

Estimated Saudi oil export revenue (= supply – demand x prompt Brent) in ($B/b)

Many Opec members are not in Saudi Arabia’s financial position. Only Qatar, Kuwait, Angola and the UAE have by most estimates a lower budget break-even oil priced than does the Kingdom. At the other extreme, Iran appears to require the highest oil price, which is a different way to illustrate the import of the current nuclear negotiations with the P5+1. Venezuela’s finances are in perilous shape as well.

Cost-curve: Ranges of OPEC government budget break-even-prices ($/b)

Source: Credit Suisse estimates, Country Data
Most of the time OPEC withholds existing supply from the market, creating \textit{spare capacity} \textit{i.e.}, oil which could be produced, but is offline.

- We use the classic definition of spare capacity: What can be brought on line within 30-days (so as to be relevant to prompt demand); and sustained for more than 90 days (i.e. not counting the ‘surge capacity’ of reservoirs.

\textbf{Anticipated levels of future spare capacity have important effects on crude prices generating more or less fear about supply (see markets and pricing section).}

- Generally, markets since 2002 have had less than 3 Mb/d of spare capacity (except during the GFC)

\textit{Source: IEA, Credit Suisse estimates – adjusted for Libya}
Core OPEC Capacity Should Remain Low in Our MT/LT Forecast

Instability and sanctions have taken ~2.1 Mb/d of productive capacity offline in Libya and Iran. By year end we expect Saudi Arabia’s supply push to have brought down the Kingdom’s annual average spare crude production capacity to just 2.26 Mb/d.

Our view of the US and OPEC grabbing market share from non-OPEC ex-US assumes the return of Iranian crude production to ~4.1 Mb/d and Libyan production to 1.4 Mb/d.

Once the markets have ‘Rebalanced,’ if Saudi Arabia doesn’t pair back its production, we would be left without much in the way of spare capacity to balance the market in the event of a supply disruption.

### OPEC spare/offline productive capacity (Mb/d)

![OPEC spare/offline productive capacity graph]

**Source:** Credit Suisse estimates, HPDI, Woodmac

### Crude production (history and forecast) in Libya, Iran and Saudi Arabia as well as Saudi Arabian production limits

![Crude production graph]

**Source:** Credit Suisse estimates, HPDI, Woodmac
Iraq Likely the Main Oil Supply Wild Card

The biggest single growth prospect

- Kurdistan: A vast and underexplored onshore Basin with >40bn bbls of oil and ~100tcf of gas yet to be discovered
  - Wells exhibit strong flow rates and are low cost to develop allowing rapid production growth
  - Issues are above ground, however some progress is being made – KRG Baghdad breakthrough of late 2014.
  - For Turkey, Iraqi Kurdistan is strategic for (a) security and (b) energy independence/diversification.
  - Production capacity is ramping up to 500 kb/d and should rise to over 1mbd this decade (CS estimates). Much depends on access to international markets.

- Southern Iraq Also Making Progress:
  - Iraq has recently increased its production to north of 3.2 Mb/d, due to both infrastructure improvements and field work in at least some of the nine critical ‘mega’ jv areas.
  - Further advancements in production are possible if the rig count rises and if very large scale joint water injection investments are made, all subject to stability above ground.

Source: MEES, Credit Suisse
Oil Reserves Decline -- a Simple Yet Profound Characteristic

According to SLB, 30% of current production needs replacing by 2020, just 5 Years Away. We note that the decline rates shown below are “unmitigated” and that this chart ignores the investments that are currently underway.

Source: SLB
Oil Decline Is a Real Challenge

CVX estimate that around 50mbd of new production will be required by 2035. Total estimate around the mid-40 MBD range. Shale can provide a near term fly-wheel but eventually other types of production will be required.

Each year, new fields are needed to offset decline and rising demand

Source: CVX
Observed “Project Level” Decline Rates by Country
The decline rates shown below INCLUDE infill drilling capital expenditures

“Mitigated” observed decline rate on declining production, observed project actuals 2005-2014 (a period of $80’s bbl oil prices)

Where to Look for Decline?

“Fields that are already declining” seems a good place to start

- We observe around 4-5mbd of annual decline on the global fields that are already in decline
- This decline gets offset by growth on existing production, shale and the new fields that are being developed
- Observing decline in real time is tricky, but we note decline rates tend to accelerate when industry cashflows are constrained. We have modeled a 200bps rise in non-OPEC decline in 2015-’17.

Non-OPEC production that has been in decline, 2010-2014

Aggregate decline on non-OPEC and OPEC “declining production” (KBD)

Source: HPDI, Credit Suisse estimates
Introducing A “Declining Production Tracker”
Not yet “declining” on a year over year basis but rolling over

- In order to track whether decline is starting to kick in, we focus on the production of a subset of non-OPEC and OPEC producers which were more prone to decline.

- The leading edge of this decline-prone basket of producers is rolling over in non-OPEC and in OPEC. The pace of decline will play an important role in shaping the futures curve in 2015/2016.

Non-OPEC seasonally adjusted decline tracker

![Graph showing non-OPEC seasonally adjusted decline tracker]

OPEC seasonally adjusted decline tracker

![Graph showing OPEC seasonally adjusted decline tracker]

Note:
Includes Russia, Mexico, Kazakhstan, Brazil, Canada, Azerbaijan, Norway, Colombia, Indonesia, US GoM, UK, Egypt, Malaysia, Argentina, Thailand, Equatorial Guinea, Australia

Note:
Includes Angola, Nigeria, Algeria, Ecuador, Venezuela

Source: Woodmac, Credit Suisse estimates
International Activity Is Falling but Not as Fast as That in the US

Momentum of development is carrying global (ex Saudi) oil production upward. While rig counts have plunged in the US, activity ex-US will react more slowly

Global production ex-Saudi Arabia (Mb/d)

Non-OPEC production ex-US (rhs) vs. US production (lhs)

US CAGR:
2004 - 2010 = 1.77%
2011 - Jan. '15 = 11.88%

Non-Opec (ex-US) CAGR:
2004 - 2010 = 0.70%
2011 - Jan. '15 = -0.31%

Source: Credit Suisse Research, IEA, EIA, JODI, Petrologistics, Baker Hughes, Country Data
Oil Supply: US Shale
Before We Move To Shale; One Wrinkle
Not All Existing Production is Declining, Some Fields Are Relatively Young and Their Production is Rising

Production From Fields That Were Online in 2014 With A Higher Peak in 2019

Source: Woodmac, Credit Suisse Research
The Big picture of the “US Shale Revolution”

Shale Oil Production From Key Basins Has Grown to 5.45mbd, at a cost of ~$150billion per year

US Shale Oil Production History By Play

Source: EIA Drilling Report
Shale Well Productivity Continues to Improve

In coming years, we expect the industry to high-grade its choice of drilling location. We also expect further gains from technology.

90d CUMs Improvement

Source: EIA Drilling Report, Credit Suisse Estimates
Technology is Not Yet Fully Deployed Across the Industry

Still room to lower costs AND to maximize the recovery per well

- Industry has made great strides in maximizing the number of completions per well and lowering the time it takes to “Drill and Complete” wells (e.g. PAD drilling)

- “Engineered completions” can increase EUR’s substantially e.g. as the industry maps the subsurface to optimize frac placement with new completions and fluids. New technology can reduce horsepower 50% per well while increasing IP 20-50%

- DUC’s and refracs create a lower cost inventory to work off (though the scale of this opportunity needs to be placed in context)

Drilling Execution Efficiency Platform (DEEP)

Cumulative Oil Production

Source: COP 2015 Analyst Day
Eagle Ford “Half-Cycle” Breakevens of 2014 Wells

% Production Uneconomic @ $75 WTI (20% Cost Deflation): 11%
% Production Uneconomic @ $60 WTI (20% Cost Deflation): 23%
% Production Uneconomic @ $50 WTI (20% Cost Deflation): 32%

Source: HPDI, Credit Suisse estimates
Show me a price: Outcomes for the “Call on American Shale”

Shale Volumetric Outcomes Are Highly Dependent on IP Improvements

- Industry is high-grading and deploying technology improvements
- “40% of perforation clusters do not produce, 40% of fractures do not produce, 40% of the wells are uneconomical” SLB 2014 Analyst Day. New technologies – 20-50% higher 50 day cum; 50% less horsepower, 20-50% less water
- The required oil price to deliver our projected “Call on American Shale” will depend on the interplay between deflation, technology gains, and high-grading.

Shale oil production potential from key basins (40-50% improvement in IP from high-grading and steady technological improvement)

Pace of High Grading and Technology Development Can Have a Large Impact on Volumetric Forecasting:

Source: HPDI, Credit Suisse estimates
Near Term Supply Side Developments to Watch in US Shale
The US drilling rig count will likely fall by 1,000 units, after years of steep growth.

Stupendous growth in the US tight oil basins needed massive drilling programs. Less cashflow = less capex = less drilling. A leading indicator of US oil production growth is the number active drilling rigs. We keep an especially close eye on the active ‘horizontal’ rig count in the key oil plays.

The US drilling rig count will likely fall by 1,000 units, after years of steep growth.

The suddenly fast falling horizontal rig count in the big oil plays should matter.

Even the Permian, which has the greatest volume of the best rocks and the best economics is not being spared.

The impact on production will not become clear for months yet. We like keeping an eye on the yoy, and mom shifts volume growth.

Source: CS Research, Baker Hughes rig count report, US Dept of Energy’s EIA.
US Production Momentum – The EIA Shale Productivity Report

We like this new tool. It is timely, internally consistent and gives a complete picture of all the key shale basins. Its latest message: Production is rolling …

Shale production growth is fading

- The below chart clearly shows the acceleration of growth of US shale oil production in 2014
- Equally clearly, that growth has begun to roll
- The data are imperfect but the idea is clear

Because the rig count has plunged by half

- With fewer than 800 rigs drilling for oil in the four big plays in February new oil additions fell below legacy decline, for the first time in 5 yrs
- US oil supply is probably slipping mom

The monthly count of rigs drilling for oil in these plays set against: new well output; legacy decline; and the implied monthly addition / subtraction of US shale oil supply (through June, Kb/d)

Source: Department of Energy’s Energy Information Agency
How This Fits into a Rebalancing: The NT “Call on American Shale”

In our central scenario, the fast plunging rig-count drives a steep decline of US crude oil production -- around which we sketch a RANGE as well.

Elements of our central scenario, and the upside / downside cases:

■ In our base case, see also the global balance tables, we project that Saudi Arabia’s crude oil production remains at current levels (~10.3 Mb/d); that Iran’s exports begin to rise marginally in July, and then expand by another 300 kb/d in September and a final 300 kb/d in January 2016.

■ The upside case simply takes Saudi Arabia’s output down to 10 Mb/d; includes incremental exports from Iran beginning only in H2-2016; and allows for 200 kb/d less growth from Iraq in 2016.

■ The downside case assumes global demand growth this year and next of only 1% (not the ~1.5% growth of our base case).

Source: Credit Suisse Research, IEA, EIA, JODI, Country Data, WoodMac
Oil -- Demand
Oil is a cyclical commodity (with managed characteristics)

Higher oil prices during booms tend to create deeper demand recessions afterwards

And soon we will see if lower prices can generate lasting upside for demand

Source: Credit Suisse Research
Increasingly, Oil Is Becoming a Consumer Good

Oil demand grew by a CAGR of 1.2% from 2002 to 2014. We expect global oil demand to rise by about 1.5% in the next few years.

Oil demand growth has historically correlated with IP growth, but not exclusively so. Price, taxation and fuel switching have all driven significant changes in patterns of oil use.

The future of oil demand growth is no longer in the OECD: but in Emerging Markets.

The principal uses for oil are transportation, power generation, heating & chemical feed

- The highest value use of oil today is as a transportation fuel and specialty chemical feedstock
- As countries become richer they tend to reduce or phase out their industrial uses of oil

Oil demand is price elastic as a rule. Different consuming zones exhibit different elasticity.

- This is due to:
  - Different end user taxation levels (the US and China have low taxes, Europe has high taxes)
  - Political and economic stability and the availability of substitute fuels.

Over time, oil demand becomes more consumer-driven rather than industrial
Oil Demand Correlation with Real GDP Growth (1969 - 2008)

Global GDP trends are a clear underlying driver of oil demand.

However, the relationship is uneven and consuming regions exhibit very different demand multipliers to GDP. A broad rule of thumb maybe ~ 0.7 in emerging economies, ~0.2 ish in the OECD.

- Note as well that US oil consumption can still rise cyclically, after having been decimated by substitution (cheap natural gas) and again by the GFC of 2008
- Oil consumption across northwest Europe and in Japan is trending down more unambiguously

Source: BP Stats, Credit Suisse estimates
Oil Demand: the Funny Part Is that it Is Still Growing

- In the past 20 years, Asia-Pacific has nearly doubled its oil consumption to 32 Mb/d
- ... few people remember that the combination of Latin America, Africa and the Mideast also doubled its oil use to ~19 Mb/d, more than a fifth of global oil consumption
- North America remains home to fully one quarter of all oil use
- Only in northwest Europe and in Japan is oil consumption clearly trending down

Source: BP Stats
... Rising Living Standards Across EM Propel that Growth

Source: OECD
Global Oil Demand: We See the Glass as Half Full

The driver of oil demand growth remains transportation-demand in emerging market economies, including China

**OECD Ex-US is declining, but is only one piece to the global demand puzzle (kb/d)**

**China oil demand is trending higher, low oil prices should help (kb/d)**

**US oil demand has not yet gone into trend decline, has cyclical upside (kb/d)**

**Ex China EM oil demand is trending higher, low oil prices should help (kb/d)**

*Source: BP Statistical Review of World Energy 2014, Credit Suisse Research*
Near Term Demand Side Developments to Watch
The NT Demand Outlook: A Fairly Benign Macro

Worries remain, yet global growth remains the most likely outcome

2014 was a materially worse year for global oil demand growth than we anticipated. However, it was not near as bad as many feared, and growth began to ‘re-accelerate’ in a way that many have only realized quite recently.

- We observed earlier this year that global industrial production had declined sharply through the first nine months of 2014. But in the below picture it is clear that indeed the momentum trough was reached in August and that growth resumed (and actually accelerated into year-end). Significantly, other measures of global activity, all based on real data, rebounded alongside.
- While things more recently have slowed down, indeed global IP momentum peaked in January, we don’t anticipate a rolling over into a new soft-patch.

Longer history and real/relevant measures of activity: Global Goods Demand, Production and Trade
– in which Goods Demand is Adjusted IP Components from \((C + I + G - M)\)
Oil Macro – the Micro of Seasonally Adjusted Monthly Demand Data

The bearish extrapolation of weak 2Q14 demand proved misguided. Demand growth re-accelerated through much of 2H14 and is off to a strong start of 2015.

Global oil demand growth did not roll over …
(SA, 3mma of monthly data on a LN scale)

… instead OECD oil demand began to rebound in H2-2014
(SA, 3mma of monthly data on a LN scale)

Source: Credit Suisse Research, IEA, EIA, JODI, Country Data
Oil Macro – Seasonally Adjusted Demand (con’t)
Non-OECD Growth is Respectable, Despite Asia Slowing

Non-OECD oil demand growth is not much to write home about (SA, 3mma of monthly data on a LN scale)

EM Asia ex-China ended 2014 a little sluggishly, then gained momentum (SA, 3mma of monthly data on a LN scale)

Non-OECD demand momentum, mom and yoy 3 mma % change

EM Asia ex-China oil demand data, mom and yoy 3 mma % change

Source: Credit Suisse Research, IEA, EIA, JODI, Country Data
Oil Macro – Seasonally Adjusted Demand, US
A Recovery in US Oil Demand, With Gasoline In The Lead

US (SA, 3mma of monthly data on a LN scale)

US oil demand data, mom and yoy 3 mma % change

US oil demand growth by product (annual averages in kb/d, yoy)

Source: Credit Suisse Research, IEA, EIA
Oil Macro – Seasonally Adjusted Demand, Europe & China
A Surprisingly Robust EU recovery, and A Strong yoy Rebound in China

OECD Europe, after 7 lean years … (SA, 3mma of monthly data on a LN scale)

China’s oil demand still grows at a +3% pa rate, base effects flatter the first half of this year (3mma of monthly data, kb/d)

OECD Europe oil demand data, mom and yoy 3 mma % change

China oil demand data, mom and yoy 3 mma % change

China’s oil product demand adjusted for gasoline and diesel inventory shifts

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<th>Product</th>
<th>2014</th>
<th>2014ytd</th>
<th>Feb*</th>
<th>2015 ytd</th>
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<td>2,214</td>
<td>2,365</td>
<td>2,463</td>
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<td>Kerosene</td>
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<td><em>Drive</em></td>
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<td>6,435</td>
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<td><em>Burn</em></td>
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<td>2,566</td>
<td>2,606</td>
<td>2,627</td>
<td>2,731</td>
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<tr>
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<td>8,543</td>
<td>8,478</td>
<td>8,953</td>
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<td>4.8%</td>
</tr>
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</table>

* three month rolling average. *Drive* = gasoline + diesel + kerosene

Source: Credit Suisse Research, IEA, JODI, NBS
Oil Markets
Oil Markets: Global in Nature

- Oil is produced on nearly every continent. A complex transportation and refining system exists to move oil to end-user markets.
- We estimate that the physical global crude trade is c$2,500-billion-per year at $70/bbl oil and baseline global demand of 92 MBD.
- Variations in the U.S. dollar exchange rate also play a significant role for crude price given that oil is traded in U.S. dollars. Geopolitics and speculation also influence the price of oil.
- Crude oil is largely purchased by refiners to convert into refined products such as gasoline, as well as by power generation plants.
- Futures are traded on major exchanges such as the NYMEX and the ICE.
Oil Markets: NYMEX

- The NYMEX light, sweet crude oil futures contract is the world’s most liquid forum for crude oil trading and is also the world’s largest-volume futures contract trading on a physical commodity.
- The contract trades in units of 1,000 barrels, and the delivery point is Cushing, Oklahoma.
- The contract provides for delivery of several grades of domestic and internationally traded foreign crudes.
- **850,000** contracts are traded on average per day (futures + options).

Source: BBC
Oil Markets: Trading

- Futures trading: standardized, exchange-traded contracts in which the contract buyer agrees to take delivery, from the seller, a specific quantity of crude oil at a predetermined price on a future delivery date.

- Over-the-Counter Swaps etc: instead of trading via a futures exchange, buyers and sellers of crude oil can enter into an over the counter transaction, often known as a swap. These contacts have become more popular than futures trading in recent years, but can prove difficult to liquidate at times of market dislocation.

- Term contracts: private contracts to buy specified quantities of crude oil at prices based on regional benchmarks. These contracts are not traded in any form. Most Kuwaiti crude oil is sold on term contracts, with the price of Kuwaiti crude oil tied to Saudi Arabian Medium (for western customers) and a monthly average of Dubai and Oman crudes (for Asian buyers).
Oil Markets: Data Sources

- International Energy Agency (IEA): Every month, the IEA releases the “Oil Market Report,” which contains information on supply, demand, stocks, prices, and refinery activity.
- U.S. Department of Energy: The DOE provides weekly information on crude and principal petroleum products in regards to factors such as supply, imports, inventories and refinery activity.
- Market participants utilize these types of data sources in order to form opinions on companies as well as the expected direction of the commodity.

Source: IEA
The shape of the 12-month **futures curve** is often interpreted as an indication of current supply/demand balances.

An upward sloping curve suggests higher expected prices and implicitly higher demand relative to supply in the future: **In practice, Contango is most common with oversupply in the front month.**

A downward sloping curve suggests current demand is outpacing current supply with the expectation that the imbalance will become less pronounced in the coming time period: **In practice, Backwardation is most common with tight supply and demand in the front month.**

**Futures Curve: Contango Example**

**Futures Curve: Backwardation Example**

*Source: Bloomberg*
Swap
Transaction Overview – A WTI Example

- In order to eliminate its exposure to oil and natural gas prices moving lower, producers may choose to execute commodity swaps for their anticipated future production
  - The producer agrees to receive a fixed price from CS and the producer pays a floating price to CS which would mirror the producer’s physical commodity sales for a specific volume and tenor
  - In effect, the producer locks in the price that it will sell its future oil or natural gas supply
- Swap is zero-cost at inception
- Swap provides full downside protection while avoiding any initial cash outlay. However, a swap also eliminates the producer’s ability to benefit in the event that the price of the underlying rises

WTI Swap - Calendar Strip Pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cal 15</td>
<td>$87.50</td>
</tr>
<tr>
<td>Cal 16</td>
<td>$83.00</td>
</tr>
</tbody>
</table>

Note: Pricing is indicative only and subject to prior internal credit approval
Prices are quoted in $/bbl

NYMEX NG Swap - Calendar Strip pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cal 15</td>
<td>$4.20</td>
</tr>
<tr>
<td>Cal 16</td>
<td>$4.15</td>
</tr>
</tbody>
</table>

Note: Pricing is indicative only and subject to prior internal credit approval
Prices are quoted in $/bbl

This information reflects the Credit Suisse marks as of March 20, 2014
Source: Credit Suisse Research
Put Option
Transaction Overview – A WTI Example

- The client may consider purchasing a put to protect it from WTI prices moving below the strike price of the put.
- The client pays an upfront or deferred premium to CS and receives protection in the event that oil prices fall below the put strike, but also retains the ability to benefit from market prices moving higher.
- For a specific volume and tenor, CS will pay the client the price difference should prices fall below the put strike.
- Due to the volatility of the underlying product, time value, and liquidity in the options market, longer dated puts can become expensive on both on an upfront and deferred premium basis.

WTI Put - Calendar Strip Pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>Put Strike</th>
<th>$80.00</th>
<th>$85.00</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cal 15</td>
<td>$4.00</td>
<td>$6.00</td>
<td></td>
</tr>
<tr>
<td>Cal 16</td>
<td>$6.50</td>
<td>$8.80</td>
<td></td>
</tr>
</tbody>
</table>

Note: Pricing is indicative only and subject to prior internal credit approval.
Prices are quoted in $/bbl.

NYMEX NG Put - Calendar Strip Pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>Put Strike</th>
<th>$3.75</th>
<th>$4.00</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cal 15</td>
<td>$0.20</td>
<td>$0.30</td>
<td></td>
</tr>
<tr>
<td>Cal 16</td>
<td>$0.25</td>
<td>$0.35</td>
<td></td>
</tr>
</tbody>
</table>

Note: Pricing is indicative only and subject to prior internal credit approval.
Prices are quoted in $/bbl.

This information reflects the Credit Suisse marks as of March 20, 2014.
Source: Credit Suisse Research.
Put Spread

Transaction Overview – A WTI Example

- As a complement to a purchased put, the client can sell a lower struck put, creating a put spread.
- The sold put helps to partially offset the cost of the purchased put, decreasing the initial cash outlay.
- If the underlying WTI price remains above the purchased put strike, both put options will expire worthless and the client will forfeit the initial upfront or deferred premium to be paid to CS.
- Client’s downside protection is limited to the difference in the strike price of the purchased and sold put options, but it maintains full upside participation.

### WTI Put Spread - Calendar Strip Pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>$65 - $80 Put Spread</th>
<th>$70 - $85 Put Spread</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cal 15</td>
<td>$3.00</td>
<td>$4.00</td>
</tr>
<tr>
<td>Cal 16</td>
<td>$4.50</td>
<td>$6.00</td>
</tr>
</tbody>
</table>

**Note:** Pricing is indicative only and subject to prior internal credit approval. Prices are quoted in $/bbl.

*This information reflects the Credit Suisse marks as of March 20, 2014. Source: Credit Suisse Research.

### NYMEX NG Put Spread - Calendar Strip Pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>$3.00 - $4.00 Put Spread</th>
<th>$3.50 - $4.00 Put Spread</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cal 15</td>
<td>$0.25</td>
<td>$0.20</td>
</tr>
<tr>
<td>Cal 16</td>
<td>$0.30</td>
<td>$0.25</td>
</tr>
</tbody>
</table>

**Note:** Pricing is indicative only and subject to prior internal credit approval. Prices are quoted in $/bbl.
Costless Collar
Transaction Overview – A WTI Example

- Counterparties choosing to enter into a collar participate in both the upside market price move and downside market price risk between the purchased put and sold call strike prices.
- The premium of the sold call offsets the premium of the purchased put, reducing or eliminating any initial cash outlay.
- While the client retains protection in the event that WTI prices fall below the put strike, a collar also limits the client’s ability to benefit in the event that prices rise above the call strike.
- Client must consider the volatility in the options market in order to determine if this structure is attractive, as exposure to downside price movements could be larger than the potential upside from prices rising.

### WTI Costless Collar - Calendar Strip Pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>Put Strike</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$80.00</td>
</tr>
<tr>
<td>Cal 15</td>
<td>$94.00</td>
</tr>
<tr>
<td>Cal 16</td>
<td>$86.50</td>
</tr>
</tbody>
</table>

**Note:** Pricing is indicative only and subject to prior internal credit approval.
Prices are quoted in $/bbl.

This information reflects the Credit Suisse marks as of March 20, 2014.
Source: Credit Suisse Research

### NYMEX NG Costless Collar - Calendar Strip pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>Put Strike</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$3.75</td>
</tr>
<tr>
<td>Cal 15</td>
<td>$4.90</td>
</tr>
<tr>
<td>Cal 16</td>
<td>$4.75</td>
</tr>
</tbody>
</table>

**Note:** Pricing is indicative only and subject to prior internal credit approval.
Prices are quoted in $/bbl.

---

**Payout Diagram**

- Collar (Purchased put & Sold call)
- Unhedged

---

**Swap**

- Spot Market Price
Producer Three-Way
Transaction Overview – A WTI Example

- As an alternative to the traditional collar, a client may also like a three-way
- A producer three-way is a combination of the traditional collar paired with the sale of a lower struck put
- The premium from the sold put can be used to increase either the purchased put or sold call strikes on the collar
- This hedging strategy is ideal in low price environments when the client is fairly confident that underlying prices will not move below the sold put strike. Volatility in the options market will have an impact on the put and call strike prices
- Client is fully protected as long as prices do not fall below the sold put strike and retains upside participation up to the call strike

WTI Three-Way - Calendar Strip Pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>Put Strikes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$65 / $80</td>
</tr>
<tr>
<td>Cal 15</td>
<td>$96.75</td>
</tr>
<tr>
<td>Cal 16</td>
<td>$91.50</td>
</tr>
</tbody>
</table>

NYMEX NG Three-Way - Calendar Strip pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>Put Strikes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$3.00 / $4.00</td>
</tr>
<tr>
<td>Cal 15</td>
<td>$4.60</td>
</tr>
<tr>
<td>Cal 16</td>
<td>$4.50</td>
</tr>
</tbody>
</table>

Payout Diagram

This information reflects the Credit Suisse marks as of March 20, 2014
Source: Credit Suisse Research

Note: Pricing is indicative only and subject to prior internal credit approval
Prices are quoted in $/bbl
Double-Volume
Transaction Overview – A WTI Example

- To achieve an enhancement above the current market price, producers may be interested in a Double-Volume swap.
- A producer Double-Volume consists of a sold swap and a call swaption both at the same price.
- The premium from the call swaption is used to increase the level of swap.
- The call swaption has one expiration date. If the underlying swap settles above the strike price, CS will "Double" the volume of the transaction.
- This hedging strategy is most suitable for companies who intend to vary their production based on the market price and have some flexibility on the % of their production that is hedged.

WTI Double-Volume – Calendar strip pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cal 15</td>
<td>$90.50</td>
</tr>
<tr>
<td>Cal 16</td>
<td>$87.10</td>
</tr>
</tbody>
</table>

Note: The Double-Volume structures above have call swaption expiration dates on the quadultimate settlement of the January portion of the swap.

NYMEX NG Double-Volume – Calendar strip pricing

<table>
<thead>
<tr>
<th>Tenor</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cal 15</td>
<td>$4.40</td>
</tr>
<tr>
<td>Cal 16</td>
<td>$4.30</td>
</tr>
</tbody>
</table>

Note: The Double-Volume structures above have call swaption expiration dates on the quadultimate settlement of the January portion of the swap.

*This payout diagram assumes that the transaction volume is not doubled.

Source: Credit Suisse Research
Near Term Oil Market Backdrop and Developments
The 2014-'15 Oil Price Collapse in History

In prior episodes, the first inflection point came in the third quarter too.

We think that we will be proved right that prices troughed in 1Q15. To be sure at $80/b Brent; $75/b WTI, our projected recovery would fall far short of the five-year running average of Brent oil prices, which crept over $100/b in June of 2014.

The extent and depth of this oil price collapse feels most like that of 1998 (less bad than in 2009) in terms of the attendant collapse in Brent structure.


While evidently the 2014 price collapse dwarfs anything since 2010, it is fundamentally different from the acute collapse of oil demand in late 2008.

That said, we are seeing a similarly massive inventory surplus developing

... and we can also see the contango structure persist for another year.

Back in the late 1990s, the Asian Financial Crisis had undermined oil demand. Weak demand was compounded by Saudi Arabia engaging Venezuela in a struggle for US market share. Affirmation came at a fateful Opec meeting in Jakarta, Indonesia late in 1997.

Prior extended stretches of oversupply (contango) ended after five quarters (1998); two and a half years (2007); and three years (2010).

But in all three episodes, things stopped getting worse after two to three quarters – and we think that history is repeating itself.

Long history of month 1-6 of Brent futures: deep contango is rare ($/b)

Overlay of terms of ‘cost of carry’ pricing of Brent futures of two prior crises

Source: Credit Suisse Research, Bloomberg
Short term S/D balance + a Shifting Long Term ‘Anchor’

Some prompt price recovery and an appreciating long-end

A few assumptions / thoughts / observations about our favorite barometers on the health and direction of crude oil:

- Perhaps naively, we look at markets as clearing information timely and efficiently.
- Futures markets inform about the short term (structure) and the longer run (level).
- Since we expect that markets will remain saddled with very heavy inventories, and that consequently contangoes remain pronounced; more of our projected 2015 price appreciation comes from a shift in the long end of the curve …
- … that shift happens in earnest as confidence builds – which happens most likely along with data that show demand growing and supply rolling. It would help too if markets got a clearer line of sight on the industry ability to compress costs.
- Keep an eye on December 2017 futures prices and the shape of the front end of the Brent futures curve.

Oil prices have recovered a bit, Brent has risen some 45% off its January low. A measure of ‘normal’, the longer dated price fell less, but also recovered less ($/b).

Global crude oil markets remain over-supplied, though less depressingly so (Brent futures contract month 1 – month 6; $/b)

Source: Credit Suisse Research, Bloomberg
Six Months into a “Go Stabilize Yourself” World

Oil is still fundamentally weak, but rebalancing has begun

Traders spent four years ruing the lack of volatility – the one thing we are confident of is more volatility.

What we learned: The oil price collapse of H2-2014 was not a ‘canary in the coal-mine’ type signal of a collapsing global economy. That said, true strengthening of fundamentals is not likely to begin in earnest until H2 2015 and futures curves will probably not flip backward until well into 2016.

- Oil prices should trend up instead on relative improvements of supply/demand fundamentals...
- …And on building confidence about the longer run deceleration of supply growth as well as sustained demand growth.

Trading oil markets has become quite ‘interesting’, if not outright scary. Since the global recovery has accelerated, however haltingly, energy has been screening “very cheap” to all manner of investors.

- Attendant record high open interest of oil futures, big moves in currency, rates, equity markets and as yet very low conviction on pure oil fundamental direction all appear to have created an environment ripe for ubiquitous algorithmic trading to whipsaw oil prices on any given day.

Quarter average WTI oil prices for this year and the next two, including our forecast, the futures strip and the oil price track of 2008-’10, GFC ($b)

<table>
<thead>
<tr>
<th>Brent</th>
<th>WTI</th>
<th>WTI - Brent</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actuals &amp; Forecast</td>
<td>Prior Forecast</td>
</tr>
<tr>
<td>Prior</td>
<td>Forecast</td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td>$110.91</td>
<td>$95.11</td>
</tr>
<tr>
<td>2012</td>
<td>$111.68</td>
<td>$94.15</td>
</tr>
<tr>
<td>2013</td>
<td>$108.70</td>
<td>$98.05</td>
</tr>
<tr>
<td>Q1-2014</td>
<td>$107.87</td>
<td>$98.56</td>
</tr>
<tr>
<td>Q2-2014</td>
<td>$109.76</td>
<td>$102.99</td>
</tr>
<tr>
<td>Q3-2014</td>
<td>$103.59</td>
<td>$97.34</td>
</tr>
<tr>
<td>Q4-2014</td>
<td>$76.82</td>
<td>$72.94</td>
</tr>
<tr>
<td>2014</td>
<td>$99.38</td>
<td>$92.89</td>
</tr>
<tr>
<td>Q1-2015</td>
<td>$55.13</td>
<td>$48.56</td>
</tr>
<tr>
<td>Q2-2015f</td>
<td>$54.00</td>
<td>$53.00</td>
</tr>
<tr>
<td>Q3-2015f</td>
<td>$62.00</td>
<td>$60.00</td>
</tr>
<tr>
<td>Q4-2015f</td>
<td>$71.00</td>
<td>$67.00</td>
</tr>
<tr>
<td>2015f</td>
<td>$60.53</td>
<td>$58.00</td>
</tr>
<tr>
<td>Q1-2016f</td>
<td>$72.00</td>
<td>$67.00</td>
</tr>
<tr>
<td>Q2-2016f</td>
<td>$74.00</td>
<td>$71.00</td>
</tr>
<tr>
<td>Q3-2016f</td>
<td>$78.00</td>
<td>$75.00</td>
</tr>
<tr>
<td>Q4-2016f</td>
<td>$80.00</td>
<td>$75.00</td>
</tr>
<tr>
<td>2016f</td>
<td>$76.00</td>
<td>$72.00</td>
</tr>
<tr>
<td>2017f</td>
<td>$80.00</td>
<td>$75.00</td>
</tr>
<tr>
<td>2018f</td>
<td>$80.00</td>
<td>$75.00</td>
</tr>
<tr>
<td>2019f</td>
<td>$80.00</td>
<td>$75.00</td>
</tr>
<tr>
<td>Long-Term</td>
<td>$85.00</td>
<td>$80.00</td>
</tr>
</tbody>
</table>

Source: Credit Suisse Research, Bloomberg
North American Crude Oil Markets
Phase 1 (2011-12): Mid-Continent production growth was filling up inventories at Cushing (OK) where WTI is based had no exit route.

Phase 2 (2013-14): Pipes arrive to connect Cushing to the Gulf. Attention focuses on super-saturation of light oil in the medium/heavy refineries of the Gulf Coast. Permian discounts widen due to higher rig count.

Phase 3 (2015): Attention turns to the West Coast as rising crude volumes flow West, contango incentivizes crude inventories to build.

Phase 4 (LT): Infrastructure or policy (US exports) will drive spreads to transport and quality differentials.

Source: Credit Suisse Research, Bloomberg
Current Crude Flows and Costs

Expect Gulf Coast and Mid-Continent will have cost advantage versus East Coast, West Coast, and most foreign markets

Source: VLO
“Stress” in the Gulf Will Determine LLS Light Crude Oil Discount

Source: CS estimates, EIA
Without Export Clarity, Gulf Coast Will Hit Light Oil Saturation

Gulf Coast Crude Flows and Potential WTI-Brent Spreads

<table>
<thead>
<tr>
<th>Without Export Clarity, Gulf Coast Will Hit Light Oil Saturation</th>
<th>Gulf Coast Crude Flows and Potential WTI-Brent Spreads</th>
</tr>
</thead>
<tbody>
<tr>
<td>Source: Credit Suisse Research</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Exporting to World Markets</th>
<th>WTI-Gulf</th>
<th>Transshipment</th>
<th>Shipping</th>
<th>Crude Competition</th>
<th>End-Market Discount</th>
<th>WTI-Brent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exporting to World Markets</td>
<td>3.8</td>
<td>0.5</td>
<td>2.0</td>
<td>LLS vs Medium Imports</td>
<td>0.0</td>
<td>6.3</td>
</tr>
<tr>
<td>Clearing at Gulf Refiners</td>
<td>3.8</td>
<td>1.5</td>
<td>2.0</td>
<td>LLS vs Medium Imports</td>
<td>5.0</td>
<td>10.3</td>
</tr>
<tr>
<td>Clearing into Canada</td>
<td>3.8</td>
<td>1.5</td>
<td>2.0</td>
<td>LLS-Brent</td>
<td>0.0</td>
<td>7.3</td>
</tr>
<tr>
<td>Clearing into East Coast</td>
<td>3.8</td>
<td>1.5</td>
<td>4.6</td>
<td>LLS-Brent</td>
<td>0.0</td>
<td>9.9</td>
</tr>
<tr>
<td>Backing out Heavy Crude</td>
<td>3.8</td>
<td>1.5</td>
<td></td>
<td>LLS-Maya</td>
<td>7.0</td>
<td>12.3</td>
</tr>
</tbody>
</table>
Challenges Processing Light Crudes

- Refineries are designed for a specific range of crude oil properties, otherwise build costs would be very high
- Lighter crudes contain significantly more light components, e.g., propane, butane, straight run gasoline, naphtha

![Distillation Tower Diagram]

- Be careful about generalizing crude oil properties and their impact on product yields
  - Some light crudes are inherently diesel rich or gasoline rich despite having a similar API gravity
  - As we have shifted our diet to higher API domestic shale crudes (Eagle Ford, Bakken, etc.), we have seen distillate yields stay about the same, while gasoline yields have increased
- Many constraints can limit a refinery’s ability to process light components, and constraints are refinery specific
- Examples include:
  - Distillation tower has insufficient capacity for light components
  - Hydraulic capacity of overhead distillation hardware
  - Heater or heat exchanger design has insufficient capacity, flexibility or limited ability to cool and condense higher volume of light ends
  - Saturated gas plant has insufficient capacity to process additional volume
  - Downstream processing capacity limits ability to convert intermediates into finished products
- Depending on the constraint, solutions can range from $10 million to hundreds of millions

Source: VLO
## Tactical Indicators – US Storage Capacity

### Shell crude storage capacity (thousands of barrels)

<table>
<thead>
<tr>
<th></th>
<th>I</th>
<th>II</th>
<th>III</th>
<th>IV</th>
<th>V</th>
<th>US Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Refineries</td>
<td>17,443</td>
<td>1,894</td>
<td>23,166</td>
<td>1,213</td>
<td>89,287</td>
<td>2,805</td>
</tr>
<tr>
<td></td>
<td>4,614</td>
<td>160</td>
<td>39,207</td>
<td>1,060</td>
<td>173,717</td>
<td>7,122</td>
</tr>
<tr>
<td>Tank Farms (excluding SPR)</td>
<td>4,908</td>
<td>1,148</td>
<td>142,063</td>
<td>2,716</td>
<td>242,365</td>
<td>7,235</td>
</tr>
<tr>
<td></td>
<td>15,966</td>
<td>76</td>
<td>33,660</td>
<td>1,269</td>
<td>438,982</td>
<td>12,444</td>
</tr>
<tr>
<td>Of which at Cushing, OK</td>
<td>--</td>
<td>--</td>
<td>84,969</td>
<td>147</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td></td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Tankers, Barges and Pipes</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>SPR (Crude only)</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Of which at Cushing, OK</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Total (excluding SPR):</td>
<td>22,351</td>
<td>3,042</td>
<td>165,229</td>
<td>3,929</td>
<td>331,672</td>
<td>10,040</td>
</tr>
<tr>
<td></td>
<td>20,580</td>
<td>236</td>
<td>72,867</td>
<td>2,319</td>
<td>786,032</td>
<td>19,566</td>
</tr>
</tbody>
</table>

### Working crude storage capacity (thousands of barrels)

<table>
<thead>
<tr>
<th></th>
<th>I</th>
<th>II</th>
<th>III</th>
<th>IV</th>
<th>V</th>
<th>US Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Refineries</td>
<td>15,408</td>
<td>18,877</td>
<td>75,006</td>
<td>4,006</td>
<td>34,756</td>
<td>148,053</td>
</tr>
<tr>
<td>Of which is likely to be max fill in reality</td>
<td>13,082</td>
<td>17,375</td>
<td>58,037</td>
<td>3,461</td>
<td>29,405</td>
<td>121,359</td>
</tr>
<tr>
<td>Tank Farms (excluding SPR)</td>
<td>3,974</td>
<td>117,253</td>
<td>210,614</td>
<td>13,139</td>
<td>27,899</td>
<td>372,879</td>
</tr>
<tr>
<td>Of which at Cushing, OK</td>
<td>70,812</td>
<td>70,812</td>
<td>70,812</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Volumes in transit *</td>
<td>4837</td>
<td>33972</td>
<td>71277</td>
<td>4279</td>
<td>15636</td>
<td>130,000</td>
</tr>
<tr>
<td>SPR (Crude only)</td>
<td>727,000</td>
<td>727,000</td>
<td>727,000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total (excluding SPR):</td>
<td>21,893</td>
<td>168,599</td>
<td>339,928</td>
<td>20,878</td>
<td>72,940</td>
<td>624,238</td>
</tr>
</tbody>
</table>

(*) Note: Volumes estimates based on March 4, 2015 note by EIA

(**) Note: Total assumes a level of max fill at refineries below the EIA working capacity number

### Crude Oil Stocks (thousands of barrels)

<table>
<thead>
<tr>
<th></th>
<th>I</th>
<th>II</th>
<th>III</th>
<th>IV</th>
<th>V</th>
<th>US Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standard EIA stock number</td>
<td>17,624</td>
<td>146,086</td>
<td>243,864</td>
<td>24,618</td>
<td>58,720</td>
<td>490,912</td>
</tr>
</tbody>
</table>

### Crude storage capacity utilization (thousands of barrels)

<table>
<thead>
<tr>
<th></th>
<th>I</th>
<th>II</th>
<th>III</th>
<th>IV</th>
<th>V</th>
<th>US Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standard EIA stock number</td>
<td>81%</td>
<td>87%</td>
<td>72%</td>
<td>118%</td>
<td>81%</td>
<td>79%</td>
</tr>
</tbody>
</table>

### “Head Room” PADD I - IV East of Rockies 119,106

<table>
<thead>
<tr>
<th></th>
<th>Total shell capacity (incl. idle capacity)</th>
<th>Total operable shell capacity</th>
<th>Total working capacity *</th>
<th>Room* till working capacity is full</th>
<th>Three week average build</th>
<th># of weeks till full</th>
</tr>
</thead>
<tbody>
<tr>
<td>4/24/2015 PADD I - IV “East of Rockies” (excluding SPR)</td>
<td>557,079</td>
<td>539,832</td>
<td>551,298</td>
<td>432,192</td>
<td>119,106</td>
<td>2,651</td>
</tr>
</tbody>
</table>

(*) Note: has been adjusted to account for oil in transit as well as a level of max fill at refineries below the EIA working capacity number

**Source:** Credit Suisse Research, EIA
Tactical Indicators – US Product Demand and Inventory

US finished gasoline demand (Mb/d)

US middle distillate demand (Mb/d)

US gasoline inventories (Mbs)

US middle distillate inventories (Mbs)

Source: Credit Suisse Research, EIA
Finally, A Word on US Crude Export Policy

1973 - Arab Oil Embargo

1974 - U.S. Eliminated Quantitative Controls on Refined Product Exports

1975 - Congress banned the exportation of U.S. crude oil thru the Energy Policy and Conservation Act (EPCA)

1981 - Removal of Price Controls, President Regan

2009 - North Dakota Oil production > 200 mbpd

2011 - Texas' Eagle Ford oil production > 200 mbpd

2013 - U.S. Energy Secretary Muniz comments on export policies

2014 - U.S. Senator Murkowski, Congressional Hearings - U.S. Oil exports

Source: Credit Suisse Strategy, Bloomberg
US Light Shale Crude Fits Overseas Refineries Better
A US Crude Export Rationale

The US Has More Cokers than Rest of World

Almost 40% of Crude Is Medium/Heavy

Source: OGI, Credit Suisse Research
US Refiners Need to Export Surplus Product to Capture Cheap Crude Advantage, Not Immune to World Markets

Diesel Exports Help Gasoline Production

Diesel Export Destinations

Gasoline Export Destinations

Source: Credit Suisse Research, EIA, VLO
US Natural Gas: A Supply Revolution Looking for Demand
What is Natural Gas?

Natural Gas is a combustible, colorless and odorless gas generally considered the least environmentally unfriendly of the principal hydrocarbon energy sources.

Methane (which is dry gas) is the most commercially marketable component of the natural gas stream.

Other components of the typical well-head natural gas stream (wet gas) include heavier “liquids” such as ethane, propane and butane.

Natural Gas is measured on a unit basis in thousands of cubic feet (Mcf). The benchmark spot price is Henry Hub, which is quoted on a $ per Millions of British Thermal Units basis (MMBtu). An Mcf is a volume unit, while MMBtu is an energy measurement.

Because of the need for extensive pipeline systems and difficulty in shipping, natural gas is most used in regions with indigenous supply. Meanwhile, the ability to ship gas in liquid form (LNG) is gaining traction.

Photo Source: Chesapeake Energy
Distribution of Proved Gas Reserves
Count on the North America share of proved reserves to rise more

World Energy: Natural Gas Has Gained Share of the Energy Pie

According to BP Statistical Energy Review, natural gas accounted for 24% of global primary energy consumption, the highest on record, in 2012.

Global gas demand growth is currently being driven by Asia and the Middle East (due to a switch away from oil and slowing growth in coal consumption).

Power demand has been the key driver to gas demand growth globally, while industry has slowed.

Source: BP Statistical Review of World Energy 2013
Substitutes for Natural Gas

There are numerous substitutes for natural gas including **coal**, **oil**, **heating oil**, **naphtha** and **alternative energy** (such as wind, solar and nuclear power).

A global movement towards clean energy has put natural gas more in favor versus coal and oil, due to inherently lower CO2 emissions.

*Source: www.britishcoalgasification.co.uk.*  
*Source: ecotechdaily.com*  
*Source: www.greengop.org.*
N. AM. Natural Gas Pricing

- North America is mostly a “closed” market with natural gas prices driven by demand trends (weather, economic growth) and the cost of new supply.
- Over the past 14 years, NYMEX gas prices have traded as low as $2 per MMBtu and as high as $14-15 per MMBtu.
- In North America, oil and natural gas do not exhibit a strong pricing relationship as the two fuels don't compete much (oil is not used much for power while gas is not used much for transportation).
- Outside of the U.S., prices tend to be linked to crude owing to less liquid trading markets.

Source: Bloomberg LP
The process of bringing natural gas to market begins with **exploration & production** and ends with the retail **distribution** of gas to end markets.

Along the way, gas is **gathered and processed** for removal of oil, water, natural gas liquids (NGLs) and sulfur. It is then **transported** and **stored** while awaiting distribution.

*Source: Energy Information Administration*
Exploration & Production (also known as the upstream) of natural gas is a global venture and producers operate in both onshore and offshore environments.

Natural gas is located underground and below seabeds.

Producers often drill thousands of feet beneath the surface to reach natural gas reservoirs.

In North America, onshore unconventional resources like shale and tight gas sands have become a growing source of production in recent years as traditional and lower cost sources have matured.
Upstream: Exploring and Producing Natural Gas

- Producers use various techniques to **locate** and **test for the existence** of natural gas including geophysical surveys, seismic evaluation, exploratory wells, well logs, core samples and others.
- Once **commercially viable** quantities of natural gas have been discovered and confirmed, producers will **develop the reservoir** and **commence production**.
- Produced natural gas is then sent to processing facilities via pipeline.
- Please see Upstream section for additional detail on the exploration and production process.

*Source: Japan Agency for Marine Earth Science and Technology*  
*Source: www.smi-online.co.uk*
Midstream: Processing Natural Gas

Processing natural gas (midstream) involves the removal of oil, water, hydrogen sulfide, carbon dioxide and NGLs (ethane, butane and propane).

The end goal is to produce dry gas, free of impurities or other non-methane compounds to meet pipeline quality specifications so it can be transported across the US.

* Optional Step, depending upon the source and type of gas stream.
* Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division.

Source: Energy Information Administration
Midstream: Transporting Natural Gas

- Natural gas in the U.S. is delivered via a complex web of interstate and intrastate pipelines estimated to extend ~2.2 million miles.
- Pipeline companies charge regulated fees (tariffs) for moving gas.
- Major pipelines include the Transcontinental, Texas Eastern & Rockies Express.
- The majority of interstate pipelines were created to move gas from the US gulf coast (traditional supply center) the Midcontinent and Northeast (demand center).

Source: American Clean Skies Foundation
Natural Gas Marketing: What are Basis Differentials?

- The NYMEX natural gas price (Henry Hub, Louisiana) is not necessarily what producers receive for their gas. The actual price received (well-head price) is different throughout the country. The difference relative to NYMEX is called a **basis differential**.

- Regional prices are a function of local supply and demand balances and the transport cost to reach consuming markets from production areas.

- Historically, **Rockies gas traded at the widest discount** while **Appalachia gas traded at a premium** (given proximity to high demand areas on the east coast). However, **differentials have flipped** since 2012 as the Northeast began producing vast amounts of natural gas.

*Source: www.nafsa.org*
Natural Gas Storage: The U.S. has a Deep Storage System

Before being transported for local distribution, natural gas is stored in underground facilities such as depleted reservoirs, salt caverns and aquifers.

Total natural gas storage capacity in the U.S. is spread amongst 400 facilities with a design capacity of 4.68 Tcf (demonstrated capacities are much lower at 4.3 Tcf).

Regulated utilities own and operate the vast majority of US storage sites, with the rest controlled by merchant power companies or individual storage operators.

Natural gas in storage fluctuates from the withdrawal season (November to March) when cold weather typically results in storage withdrawals to the refill season (April to October) when lower demand leads to net storage injections.

Every Thursday at 10:30am ET, the EIA reports the storage injection / draw for the prior week. The amount of injection or draw can have a material affect on gas prices as it indicates supply / demand trends relative to previous years.

Source: EIA
Major End Markets for Natural Gas

**Residential**
Gas used in private dwellings for space and water heating, air conditioning, cooking and other household uses

**Commercial**
Gas used by non-manufacturing establishments in the sale of goods or services

**Industrial**
Gas used for heat, power or chemical feedstock for manufacturing. End products include petrochemicals, fertilizers, plastics, etc.

**Electrical Power**
Gas used by power plants to generate electricity

Other smaller end-market uses of natural gas include 1) fuel (natural gas vehicles) and 2) oil & gas production.

*Source: EIA*
Natural gas demand trends are highly **seasonal**.

Because natural gas is used as a heating fuel, demand rises materially in the winter/cold weather months.

**Source:** EIA
Summary View: Fundamental Change is Coming
But not likely in time to lift summer prices above $3/MMBtu at the Henry Hub

Any decelerating of supply growth and the ongoing ramping up of demand will, we think, progress too slowly to help lift gas prices this summer. The first half of the injection season looks especially challenged.

From June/July forward, however, supply growth should begin to deflate faster, while simultaneously yoY demand growth picks up and storage fill should begin to feel the competition from the first of a string of LNG export terminals.

Marking to market Q1-2015 Bid-week prices averaged $2.96/MMBtu, which was down almost a dollar from last quarter, and nearly 40% lower than in Q1-2014, despite a similar and considerable assist from colder than normal winter weather.

In winter 2014-’15 supply growth easily trumped colder than normal weather
This supply growth, however, is already showing signs of slowing down:

- We are more confident of such a slow down than in years past.
- Clearly activity is slowing down across the entire US upstream as prices of crude oil, natural gas liquids and natural gas have all deflated
- The low price/constrained-cash-flow issue is compounded by wide, negative basis diffs in key shale basins – which infrastructure build out is only slowly resolving
- Momentum of growth slowed measurably key basins in H2-02014
- Rig counts are falling and, we think that that does make a difference
- The more so since there is no new emerging champion shale basin ready to surge
- Monthly gross natural production we think peaked in December

At these prices, demand is growing too, and in addition, large new tranches of base-load demand should be added later this year

Help is ongoing from power-generation (~ 2 Bcf/d this summer); industrial use; rising exports to Mexico; slowing imports from Canada and eventually the startup of the first Gulf Coast LNG export facility, which remains on track for Q4

### Natural Gas Prices & Forecasts
(Actual bidweek & Henry Hub futures)

<table>
<thead>
<tr>
<th>Period</th>
<th>Actuals &amp; CS Forecast</th>
<th>Prior Forecast</th>
<th>Current Futures</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>$ 4.03</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>$ 2.80</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td>$ 3.67</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q1-2014</td>
<td>$ 4.90</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q2-2014</td>
<td>$ 4.56</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q3-2014</td>
<td>$ 4.07</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q4-2014</td>
<td>$ 3.96</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>$ 4.37</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q1-2015</td>
<td>$ 2.96</td>
<td>$ 2.80</td>
<td>$ 2.70</td>
</tr>
<tr>
<td>Q2-2015f</td>
<td>$ 2.70</td>
<td>--</td>
<td>$ 2.77</td>
</tr>
<tr>
<td>Q3-2015f</td>
<td>$ 2.90</td>
<td>--</td>
<td>$ 2.77</td>
</tr>
<tr>
<td>Q4-2015f</td>
<td>$ 3.20</td>
<td>--</td>
<td>$ 2.90</td>
</tr>
<tr>
<td>2015f</td>
<td>$ 2.94</td>
<td>$ 2.90</td>
<td>$ 2.80</td>
</tr>
<tr>
<td>2016f</td>
<td>$ 4.20</td>
<td>$ 4.20</td>
<td>$ 3.20</td>
</tr>
<tr>
<td>2017f</td>
<td>$ 4.50</td>
<td>$ 4.50</td>
<td>$ 3.40</td>
</tr>
<tr>
<td>Long-Term</td>
<td>$ 4.50</td>
<td>$ 4.50</td>
<td></td>
</tr>
</tbody>
</table>

Source: Credit Suisse Research, Bloomberg
The Winter That Was … Was Cold, Which Is the Worrying Part
Lots of inventory left, as production growth of >6 Bcf/d trumped all else

That much more production inflated the fundamentally bearish difference this winter to +3.5 Bcf/d, a ‘residual’ three times bigger than we forecast

- Clearly, there was a lot of cold weather, almost as much as in the prior winter
- But there was also 6.1 Bcf/d more indigenous dry gas production, driven once by the northeastern shale gas basins
- Offsetting that surge, more exports and less imports helped (0.7 Bcf/d), while industrial and other demand helped too (0.5 Bcf/d);
- But more promising is the growth of gas demand from power-gen (1.4 Bcf/d)

Weekly withdrawals of working gas set in a 15-year range with month-end labels and our pre-winter ‘normal weather’ projection (Bcf)

Population weighted heating degree days (hdds) ended well above normal

Henry Hub futures prices reset, futures hug our NT forecast ($/MMBtu)
We Project Slower Supply Growth, Despite What Happened
The “gross withdrawals” hit a record in December and came down in January

Part of the surge in H2-2014 came from ‘conventional’ production, by contrast the up-trend in aggregate shale gas production began to curb a bit

US natural gas production (“Gross Withdrawals”) probably peaked in December, we think. Here are monthlies and YoY growth (Bcf/d)

While conventional natural gas production has been on a trend-decline, shale gas has driven US supplies to record highs (monthly data, Bcf/d)

- There is no question that US natural gas production surged in the second half of last year.
- In part this was driven by new infrastructure serving the Marcellus shale in the northeast, and a ‘catch-up’ rally after severe weather in early 2014.
- Both factors compounded the very large YoY tallies of this winter
- Interestingly, however, the EIA’s accounting of aggregate gross withdrawals from the US shale basins shows a distinct deceleration in level terms this last winter, without much of an impact from weather. Apparently, conventional production surged and then peaked in December.
- Tracks for the individual shale basins show that not one of them features accelerating production growth since October of 2014.
- We think that further declining rig counts and deep cuts in capital spending portend further declines and decelerating growth
US Natural Gas – Dare We Say … “Supply Declines”

Since 2009 we have learned that to question the duration of stupendous supply growth was wrong; since December however things are pointing south

US gross gas supplies appear to have peaked

In the end price and economics do matter, even for the seemingly endless surge of US shale gas production. We think that it matters that no longer can firms simply ‘subsidize’ gas production with liquids or oil sales, or simply hope that they’re the last one on a pipe, before others are shut out …

- In April, US DoE data began to show this slowdown in its monthly report (through January). A month later the December peak in aggregate US natural gas supply is still evident;
- Rig data, scrapes and other indicators point to a slide …

Reported gross natural gas withdrawals through February (Bcf/d)

Shale production growth is slowing down fast

The EIA drilling productivity report tracks gross gas supplies from the shale plays. The driver of cheap natural gas in the United States has been the revolutionary progress in the science of shale; which allowed for prodigious supply growth.

- It seems as if at least temporarily that engine of growth is stalling …

If we are right then US natural gas markets may find the kind of fundamentals support that we have not seen in years …

Reported gross natural gas withdrawals through February (Bcf/d)

Source: Credit Suisse Research, DoE Energy Information Agency
Why We Have a Little More Confidence in Our Supply Projections
A daring thought: Rig counts do matter …

“Back in the Day” the effect of a falling rig-count was more direct. But clearly, if the rig counts fall far enough, there will be an effect, it does take longer

Some think that a lesson learned in the shale revolution is that rig-counts do not matter. Texas gas production suggests that ‘lesson’ does not always apply

Rig counts patently affected Haynesville production, albeit with a very long lag time, about two years from peak activity in early 2010

The Marcellus rig-count peaked in early 2012, but pad drilling and other gains have kept production rising -- new infrastructure fills very quickly (Bcf/d)

In Texas, the 32% ytd plunge in the number of rigs drilling (all types of rigs, drilling both gas and oil), will we think leave a mark on the gross gas production profile, which includes conventional, shale and associated gas.

But the experience in the Haynesville (which fell from star status with a thud once the Marcellus was proved up late last decade) indicates a meaningfully longer lag time between a sharp cut in activity and the consequent production response

In Texas that lag in early 2009 was three months; the much smaller ‘drilling recession’ of 2012 took effect fully six months later; in the Haynesville the two year long lag resulted from the interplay of a multitude of forces that had kept the rig count high through 2010

It’s unclear as yet whether in the Marcellus the rig count will decline much further, or what will be the impact from the 15% drop in rigs since December. We project slower growth but no rolling over of its production.
With Decelerating Supply Growth, We Model Storage Fill of 3.8 Tcf

Our residual of underlying fundamentals next summer is more bullish than most

To model end of injection-season storage fill, we assess the YoY shifts in the individual components of supply and demand (including trade) for the period March through October. Summing these shifts yields a one number residual of the underlying YoY difference in Bcf/d, which is either negative (bullish natural gas prices) or positive (bearish natural gas prices).

We then use a history of weekly degree day totals for each of the last 15 injection seasons, which yields weather driven injection tracks. We eliminate the extremes to either end and take the average of the remaining thirteen as our central case, or weather normalized forecast for end of season storage.

- The most important forecast component is the year-over-year growth of dry gas production, which we project will decelerate from 5.4 Bcf/d in April to 0.5 Bcf/d in October; thus averaging 2.6 Bcf/d this injection season.
- The shifts in trade are in line with recent trends: Imports from Canada should fall -0.4 Bcf/d; Exports to Mexico rise by +0.3 Bcf/d.
- We plugged in -0.2 Bcf for the LNG component to reflect a 1 Bcf/d jump in exports in October – which even if a tanker does not leave, will be a drain on supply or a diversion from storage just to fill and test facilities
- The key demand-variable gas use in power generation

Storage is near normal at end winter, leaving less room to fill this summer

We model a -1.4 Bcf/d residual, which is the sum of the underlying changes in supply and demand, and yields a below consensus range of weather dependent storage tracks (15 years of summer weather history; Bcf)
Key Drivers of That Greater Gas Demand From Power Generation

2015

<table>
<thead>
<tr>
<th>Change in Nat Gas Consumption (mmcf/day)</th>
<th>New Gas Demand</th>
<th>Retired Coal</th>
<th>Nuclear Shift</th>
<th>New Wind</th>
<th>New Solar</th>
<th>Net Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>+629</td>
<td>+937</td>
<td>-517</td>
<td>-216</td>
<td>-91</td>
<td>+577</td>
<td>+1,501 mmcf/d</td>
</tr>
</tbody>
</table>

Since we model everything on the power demand side on a monthly basis as well, we can report that in the second quarter our yoy power-gen demand growth averages 1.5 Bcf/d.

- That is less than the in the first quarter: for which our model had estimated +1.8 Bcf/d growth, while the actual (low price assisted 2.5 Bcf/d actual increase.

In the second half of the injection seasons, we project that demand growth accelerates to a 2.6 Bcf/d (yoy) pace.

- Drivers of that acceleration include the timing of coal-fired power-plant retirements and easy yoy weather comps.

Source: Platts, SNL Financial, Company Data, Credit Suisse estimates
# US Natural Gas: Simple supply/demand balance

(Data through January & Forecasts)

<table>
<thead>
<tr>
<th>Year</th>
<th>Dry Gas Production*</th>
<th>Offshore (GOM)**</th>
<th>Unconventional**</th>
<th>Barnett</th>
<th>Cana-Woodford</th>
<th>Eagle Ford</th>
<th>Fayetteville</th>
<th>Haynesville</th>
<th>Marcelle</th>
<th>Mississippian</th>
<th>Denver-Julesburg</th>
<th>Nebra</th>
<th>Permian</th>
<th>Granite Wash</th>
<th>Utica</th>
<th>Canadian Imports (Net)</th>
<th>Mexican Exports (Net)</th>
<th>LNG Imports (Net)</th>
<th>Total Supply</th>
<th>Total Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>58.4</td>
<td>4.1</td>
<td>3.6</td>
<td>5.0</td>
<td>1.4</td>
<td>0.3</td>
<td>2.1</td>
<td>4.1</td>
<td>1.6</td>
<td>0.3</td>
<td>0.8</td>
<td>0.0</td>
<td>4.6</td>
<td>2.2</td>
<td>0.0</td>
<td>7.0</td>
<td>-0.8</td>
<td>1.0</td>
<td>65.5</td>
<td>66.1</td>
</tr>
<tr>
<td>2011</td>
<td>62.7</td>
<td>5.0</td>
<td>3.9</td>
<td>5.9</td>
<td>1.2</td>
<td>1.1</td>
<td>2.6</td>
<td>6.7</td>
<td>3.8</td>
<td>0.5</td>
<td>0.8</td>
<td>0.0</td>
<td>4.3</td>
<td>2.4</td>
<td>0.0</td>
<td>6.0</td>
<td>-1.4</td>
<td>0.8</td>
<td>68.1</td>
<td>67.1</td>
</tr>
<tr>
<td>2012</td>
<td>66.7</td>
<td>4.1</td>
<td>3.5</td>
<td>5.8</td>
<td>1.2</td>
<td>0.9</td>
<td>2.8</td>
<td>5.1</td>
<td>8.6</td>
<td>0.7</td>
<td>0.7</td>
<td>0.0</td>
<td>4.7</td>
<td>2.2</td>
<td>0.0</td>
<td>5.4</td>
<td>-1.8</td>
<td>0.4</td>
<td>69.8</td>
<td>68.6</td>
</tr>
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</table>

*Dry gas production = gross gas production - extraction less - processing shrink

**Conventional, Offshore (GOM) and Unconventional are in gross bcf/d and won't sum to dry gas production

Source: US Department of Energy, Credit Suisse Research
Our old supply cost curve to 2020: a string of question marks, but …
… there should be easily enough low cost gas to meet demand

* Supply cost breakeven calculation assumes $90/b oil price

Source: Credit Suisse Research, Bloomberg
Global LNG: Linking Regional Markets and Often, Gas to Oil
Typical LNG Scheme

- In order to transport gas, need pipelines or liquefaction
- Liquefaction is expensive
- LNG needs dedicated shipping (insulated)
- LNG then needs to be “regassed” into usable natural gas in the end-market
- Companies experimenting with LNG vehicles – which would have LNG instead of gasoline.

Source: Cheniere
Liquefied Natural Gas (LNG)

- **Liquefied Natural Gas** (LNG) is natural gas (methane) that is chilled to liquid form.
- Natural Gas as a liquid occupies 1/600th of the space versus ambient gas, so it can then be transported.
- LNG can be transported by ship over vast distances, and by truck locally

*Source: LNG One World*
LNG: Industry Overview

- LNG is exported from regions that have an abundant surplus supply of natural gas, and often no local market.
- LNG facilities are highly capital intensive ($5-10B) and LNG vessels are $200-300MM each. Costs can vary widely by project – e.g. off (on)-shore
- While most LNG projects operate under long-term contracts (20-25 years), there is a growing spot market of ~5-6 Bcf/d.
- Spot shipments are delivered to regions with the highest netback prices (i.e., offer the highest bids for LNG cargoes).
- Contracted import prices are often based on a oil-indexed contract (such as Japanese Crude Cocktail [JCC]).

Source: Statoil, www.oilonline.com
LNG: Liquefaction

- **Liquefaction** is the process by which natural gas is converted to liquid form.
- Methane gas is piped to a liquefaction facility where it is chilled to -260°F, at which point the vapor condenses to liquid.
- The liquefied gas is then loaded on to a carrier and transported to import markets.
- Construction of a liquefaction facility can take five to seven years.
- **Key LNG Supply Markets**: Pacific Basin (Australia, Indonesia, Malaysia), Atlantic Basin (Algeria, Nigeria, Trinidad), and Middle East (Qatar, Egypt, Oman).

*Source: Statoil*
LNG: Regasification

- Imported LNG is received as shipments at terminals with regasification ("regas") capabilities.
- Regasification involves bringing natural gas back to its gaseous form through thermal energy. The gas is then stored and distributed to local end-users through pipelines.
- **Key Import Markets:** Asia (Japan, Korea, Taiwan, India, China), Europe (U.K., Spain, Belgium) and U.S. (bidder of last resort). New markets are emerging in Southeast Asia, Latin America and the Middle East.

*Source: Federal Energy Regulatory Commission*
Japan is currently the **largest importer of LNG** globally, importing 9.0 Bcf/d in 2010 as the country has few domestic means to satisfy natural gas demand.

Imports primarily come from Australia, Indonesia and Malaysia.

**Total regasification capacity is currently approximately 25 Bcf/d** with one terminal (Sodegaura) capable of importing 3.9 Bcf/d, one of the largest in the world.

*Source: California Energy Commission*
South Korea is currently the **second largest importer** of LNG globally, importing 4.3 Bcf/d in 2010.

**Current regasification capacity is roughly 10 Bcf/d** with imports primarily from Qatar, Indonesia and Malaysia.

Similar to Japan, Korea has minimal domestic natural gas production and relies on LNG to fill the gap.

*Source: www.hydrocarbons-technology.com*
LNG: Major Exporting Countries – Qatar

- Qatar is currently the **largest exporter of LNG globally**, exporting 7.3 Bcf/d in 2010.
- **Liquefaction capacity currently stands at ~10.2 Bcf/d** and should continue to grow as two recently completed projects have yet to reach plateau.
- Qatar exports gas to most markets including Japan, Korea, Spain, U.K. and the U.S.
- Exported gas is primarily sourced from the large North Field, which has estimated recoverable natural gas reserves of more than 900 Tcf.

*Source: www.hydrocarbons-technology.com*
Indonesia is currently the **second largest exporter of LNG globally**, exporting 3.0 Bcf/d in 2010.

- Liquefaction capacity currently stands at ~4.2 Bcf/d with the majority (3 Bcf/d) from the large Bontang LNG facility that includes eight processing trains.

- Indonesia plans to reduce future LNG exports from traditional LNG trains due to increasing domestic demand for gas, but recently granted project approval to Tangguh to build a third train, which should increase capacity by 0.6 Bcf/d.

- Like Australia, Indonesia primarily exports LNG to Asian markets.

*Source: www.aceproject.org*
Australia is currently the **fourth largest exporter of LNG** globally, exporting 2.5 Bcf/d in 2010.

While liquefaction capacity only stands at ~3.2 Bcf/d currently, future projects are set to raise liquefaction capacity to **10-15 Bcf/d by 2020**.

Australia primarily exports its gas to Asian markets such as Japan, China and Korea.

The $37B, 2.0 Bcf/d Gorgon LNG project is currently being developed with first production expected in 2014 or 2015. Gorgon will be Australia’s largest resources project.

*Source: www.lngpedia.com*
Key LNG Buyers (Asia/Europe) and Producers

LNG Producers, 2012

LNG Buyers, 2012

Source: BG
LNG Plants Are Capital Intensive

Source: Cheniere
Global Gas Prices: Asia LNG; Europe NBP; US Henry Hub

- Asian spot prices have varied between European prices (NBP) and oil parity
- Asia long-term proxy as upper resistance level
- Trend expected to continue

Source: BG
Rising Gas Demand in Asia; Will Shale Gas Spoil the Party?

Source: BG
LNG Markets: Tight Until 2017-2018

APAC contestable demand vs. un-contracted supply

Source: Credit Suisse estimates
LNG Markets: More Supply Needed Longer Term

Source: CVX
Japan Is Critical: LNG Buying Scenarios

Japan > 15MTpa LONG LNG in 2018
- If all optioned supply sanctions and arrives on Japanese shores
- Based on 15 nuclear plant fleet from 2016

2020E: 15% of J demand from US
- IF all optioned projects sanction

Japanese buyers already re-selling US avails:
- Chubu Electric & Osaka Gas said to have re-sold half of their off-take from Freeport LNG to LNG buyers in Europe

In Japanese interests to make the US supply appear as large as possible

Source: FACTS Global Energy, Credit Suisse estimates
LNG Markets: Substantial Supply Potential from US

Source: Credit Suisse estimates
Significant Premium to Henry Hub Required for US LNG Exports

[Diagram showing cost of supply and price range with categories: Shipping, Liquefaction, HH, Supplier margin range, Price range.]

- Margins driven by future Asia prices
- Prices set by supply-demand balance
- Europe prices set the lower limit
- Asia LT proxy sets realistic upper limit

Source: BG
## Planned Commercial Offtakers for US LNG Projects

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<tr>
<th>Liquefaction Project</th>
<th>Off-take counterparties / destination</th>
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*Source: Credit Suisse Research*
Significant Gas Discoveries in Mozambique

- 45 - 70+ TCF Recoverable Natural Gas in Area 1
- Obtained Reserves Certification
- $2.64 Billion Partial Monetization
- 3.3 MMTPA Non-Binding HOAs with Multiple Asian Customers
- Advancing Toward First Cargoes 2018

Source: APC

*Wood Mackenzie
LNG Update – Key Takeaways

- Australia – later than advertised
- Greenfield project certainty declines in new crude price world
  - We radically reduce our ‘possible’ category
- All CS ‘possible’ projects required by mid 2020’s
  - 50% of CS ‘possible’ in US
  - Failure to sanction US projects would drive buyer focus in more challenged ‘speculative’ category
- US no longer has compelling price proposition
- Key buyer increasing focus on energy security
  - Japan concerned about South China Sea delivery and geopolitical interruption risk
  - Likely pivot away from East Africa / ME and toward supply ‘zone’ of AU / PNG

- Asian price: one stasis replaces another
  - Last 3 years focused on ‘HH’ pricing, now redundant
  - Buyers & sellers will investigate multiple pricing ideas, floors (and ceilings), higher constants, ‘new’ S curves
  - In reality unlikely either side will commit until crude price settles

Interim solution? More frequent price reviews or price at 1st LNG…
Greenfield Projects Less Robust in Low Crude Price Environment

We move multiple projects from ‘possible’ to ‘speculative’

‘Full-blown’ FLNG – not in this environment….

Abadi / Browse

- Will FLNG ‘lite’ leapfrog its gold plated brethren?
- Cameroon / Ophir EG

Canada cost re-cycling

- PacNorthWest
- CVX Kitimat on ‘go slow’

Lavaca Bay – the 1st US casualty?

PNG the attractive postcode in Asia

Source: Credit Suisse Estimates

CS: previous vs current ‘Possible’ project volumes

CS: ‘Possible’ project list

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<th>Country</th>
<th>Project Description</th>
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‘Possible’ becomes Necessary…

Previous Supply / Demand Balance

![Graph showing Previous Supply / Demand Balance](image1)

Current Supply / Demand Balance

![Graph showing Current Supply / Demand Balance](image2)

Previous / Current Producing + Under Construction + Possible vs Demand

![Graph showing Previous / Current Producing + Under Construction + Possible vs Demand](image3)

CS: Current Producing + Under Construction + Possible vs Demand (with and without US projects)

![Graph showing CS: Current Producing + Under Construction + Possible vs Demand](image4)

Source: Credit Suisse Estimates
LNG Project: Breakeven Economics

Only East Africa and PNG green-fields ‘work’ in new crude price reality

Source: Wood Mackenzie, Credit Suisse Estimates
US Supply no Longer has Compelling Price Point in Asia or Europe

But 50% of our revised ‘possible’ category are US green-fields

*Source: Credit Suisse Estimates*
### US LNG: 16MTpa Still Looking for a Home…

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<td>'EU buyer'</td>
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<td>1.1</td>
<td>1.1</td>
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<tr>
<td>Total portfolio</td>
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<tr>
<td>Total re-sold</td>
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<tr>
<td><strong>Available for re-sale</strong></td>
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<td>Tepco, Diamond Gas and Tohoku E MOUS</td>
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<td>Mitsui</td>
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<td>Tohoku</td>
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<td>2.3</td>
<td>2.2</td>
<td>TG and KE - SPA</td>
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<td>Sumitomo</td>
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<td>2.3</td>
<td></td>
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<tr>
<td>Total own use</td>
<td>2.3</td>
<td></td>
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<tr>
<td>Total portfolio</td>
<td>2.3</td>
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<tr>
<td>Total re-sold</td>
<td>2.2</td>
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<tr>
<td><strong>Available for re-sale</strong></td>
<td>0.1</td>
<td></td>
<td>4.6</td>
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*Source: Credit Suisse Estimates*
CS: Possible & Speculative Project List

Buyers may have to support more speculative projects

**CS: ‘Possible’ project list**

- US Lake Charles 2019
- US Elba Island 2019
- US Corpus Christi 2019
- US Sabine Pass T5 2019
- Papua New Guinea 3rd train in PNG 2020
- Canada Shell LNG Canada 2021
- Papua New Guinea Elk Antelope 2021
- Mozambique Mozambique FLNG 2021
- Mozambique Onshore 2022

**CS: ‘Speculative’ project list**

- Cameroon Cameroon LNG 2020
- Canada BC LNG Export 2020
- Indonesia Tangguh Expansion T3 2020
- Russia Sakhalin 2 T3 2020
- US Sabine Pass T6 2020
- Australia Browse LNG 2021
- Indonesia Abadi FLNG 2021
- US Golden Pass 2021
- Russia Far East LNG 2021
- Australia Sunrise LNG 2021
- Canada Pacific Northwest LNG 2021
- Canada Kailmat LNG 2021
- Australia Gorgon LNG T4 2021
- Mozambique Onshore 4 train 2022
- Australia Wheatstone T3 2022
- Nigeria Brass LNG 2022
- Nigeria Olokola LNG 2022
- Tanzania Tanzania LNG 2022
- US Jordan Cove 2022
- Australia Pluto LNG T2 2023
- Australia Scarborough LNG 2023
- Iran Iran LNG 2023
- Nigeria NLNG Train 7 2023
- Angola Angola LNG T2 2023
- Cyprus Aphrodite 2023
- Australia Fisherman’s Landing 2023
- US Alaska Valdez 2023
- Canada Prince Rupert LNG 2023
- Russia Baltic LNG 2023
- Australia QCLNG Train 3 2024
- Canada Goldboro 2024
- Canada Woodfibre LNG 2024
- Canada WCC (Exxon) 2024
- Australia Gorgon LNG T5 2024
- Norway Snøhvit T2 2024
- Israel Leviathan 2025
- Russia Vladivostok LNG 2025
- Equatorial GS EG LNG Train 2 2026
- Iraq Shell Iraq LNG 2026
- Australia Bonaparte FLNG 2028
- Russia Shtokman 2028

*Source: Credit Suisse Estimates*
Demand: Japan Re-emphasizing Energy Security

South China Sea – LNG trade flows 2011

- 60% of Japanese LNG travels through the South China Sea
  - A choke point too far? (Hormuz, Malacca, SCS…)
- Papua New Guinea an advantaged supply point from an energy security perspective
  - And cost to develop….
- Japan likely ‘sated’ with US supply already (although Alaska LNG could be a wildcard…)

Source: EIA, Cedigas, PFC Energy, Credit Suisse estimates
Price I – Au revoir Henry Hub pricing

- 30MT (3.95Bcf/d) commenced construction in 2014

- Cameron, Cove Point and Freeport join Sabine Pass in the construction phase for US liquefaction capacity

- 2000 – 2010 US sourced gas would have been more expensive than Japanese landed prices

- 2010 – 2014: the HH price ‘gap’ opened, on average US$5.4/mmBtu

- Recent crude price correction has closed the HH price ‘gap’ in Asia

- The US still provides a new form of supply flexibility to Asian buyers – interrupt ability (at a cost), but the price advantage has disappeared

Source: EIA, FACTS Global Energy, CS estimates
Back to the Whiteboard

Price Floors

Typical JCC contract vs Henry Hub in Asia vs price floors

Note: JCC is a 14 slope, $0.5 constant, $1 shipping example, Henry Hub is $3HH * 1.15 + 3(liquefy) + 3 (shipping)

Source: Credit Suisse estimates
Back to the Whiteboard
Higher Constants / S’s…

Typical JCC contract vs Henry Hub in Asia vs a high constant

Higher constant: in this example we raised the constant to $4/mmBtu and softened the straight line to a 9 slope (52% correlation)

- Pivot point at current crude price

S curve
- S curve I – using 2016 futures price as the fulcrum
- Unattractive for the buyer
- S curve II – using spot as the fulcrum
- Still not particularly attractive to the buyer

Source: Credit Suisse estimates
Price – Final Thought
Hard to find ‘common ground’ when crude go-forward is so uncertain

Defer the decision?
Brownfield - more frequent price review?
Greenfield - set the price at 1st cargo?

Source: Credit Suisse estimates
CS: Near-term LNG pricing in Asia

Recent S curves likely don’t offer downside protection
Price stasis as crude price finds its new trading range

Typical JCC straight line / S curve vs CS 2105 1 & 4Q Brent forecast

CS N Asia LNG price basis current Brent price forecast

Source: Credit Suisse estimates
LNG Projects
Typically Low Cash Cost Operations

Source: Credit Suisse Research
Shell / BG gross and Net Supply Concentrations - Asia

Japan

Korea

China

India

Singapore

Source: Credit Suisse Research
RDS / BG share of Greenfield Projects

Possible projects = 47% gross
(33% net)

Speculative projects = 25% gross

Source: Credit Suisse Research
An End to the “Oil Age” (and of this primer)
Renewables Consumption is Rising Fast and has a Long Runway

Other renewables consumption by region
(Million tonnes oil equivalent)

Other renewables share of power generation by region (Percentage)

Neat trends and milestones
- Germany has shifted to around >20% renewables in power generation (think wind)
- Solar Costs have fallen and are becoming more competitive in regions with high solar intensity
- Strong potential for gas, particularly in coal burning countries e.g. China

Source: BP Statistical Review of World Energy
Levelized Cost of Energy, Improvements in Wind and Solar Need Watching

Source: Credit Suisse Research
Many Ways to Improve Efficiency/Lower GHG Emissions

Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €80 per tCO₂e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.

Source: Global GHG Abatement Cost Curve v2.1

Source: McKinsey & Company
### New Transportation Technologies Emerging

<table>
<thead>
<tr>
<th></th>
<th>Natural Gas Vehicles</th>
<th>Hybrid Electric Vehicles</th>
<th>Pure Electric Vehicles</th>
<th>Fuel Cell Vehicles</th>
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<tbody>
<tr>
<td><strong>Demand drivers</strong></td>
<td>Vehicles run on natural gas (CNG or LNG)</td>
<td>Powered by a regular fuel engine and a battery</td>
<td>Electric motor powered by batteries</td>
<td></td>
</tr>
<tr>
<td><strong>Hurdles</strong></td>
<td>Low natural gas price, abundant reserves</td>
<td>Low emissions</td>
<td>Zero tailpipe emissions</td>
<td>Low emissions</td>
</tr>
<tr>
<td></td>
<td>- Highway refueling infrastructure</td>
<td>- Higher battery cost</td>
<td>- Recharging infrastructure</td>
<td>- Higher cell cost</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Higher battery cost</td>
<td>- Lack of hydrogen infrastructure</td>
</tr>
<tr>
<td><strong>Ease of Manufacturing</strong></td>
<td>Can easily retrofit conventional vehicles</td>
<td>Can easily add hybrid components</td>
<td>Needs new drive train and vehicle design</td>
<td>Can build upon an electric vehicle</td>
</tr>
<tr>
<td><strong>CO2 Kg/MMBtu</strong></td>
<td>53</td>
<td>71-73 (for gasoline/diesel)</td>
<td>0</td>
<td>0</td>
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<tr>
<td><strong>Applications</strong></td>
<td>Mainly fleets and long distance trucks</td>
<td>Passenger vehicles</td>
<td>Passenger vehicles</td>
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<td><strong>Main Players</strong></td>
<td>Westport, Clean Energy Fuels, Cummins</td>
<td>Ford, Toyota, Honda, Chevrolet</td>
<td>Nissan</td>
<td>FCEL</td>
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</tbody>
</table>

*Source: Credit Suisse Research*
Strong Demand Outlook for Natural Gas Vehicles

- **NGV?**
  - A natural gas vehicle (NGV) has an internal combustion engine which is powered by natural gas
  - Retrofit kits are available for gasoline/diesel engines

- **Global Demand**
  - Historically driven by countries with natural gas reserves (Iran, Pakistan, Argentina) or government mandates for clean and/or alternative sources to gasoline (India, China, Italy)
  - Expect strong demand from US due to low natural gas prices and better economics

- **Key catalysts to growth**
  - Growth in fueling infrastructure in US
  - Availability of NGVs produced by OEMs

- **Key players in supply chain**
  - Engine manufacturers – Cummins, Westport
  - Infrastructure and components – Clean Energy Fuels

- **Potential impact in other sectors**
  - Natural gas producers and utilities
  - Auto manufacturers
  - Capital goods

*Source: McKinsey & Company*
Automotive Battery Market Volumes and Cost Reduction Potential

- See strong demand for NiMH as Toyota's in-house production capacity has a lower cost due to high volumes (~1mm unit capacity)
- Expect strong switching from NiMH to LiB due to higher HEV demand from other manufacturers

Source: Credit Suisse Estimates, Marklines, Company data
Economics: Electric Vehicles

### Battery Breakeven Analysis (US)

#### Assumptions
- **Annual mileage**: 10,000
- **Lifecyle (years)**: 5
- **Fuel efficiency (mpg) Gas ICE**: 32
- **Fuel efficiency (mpg) Diesel ICE**: 38
- **Fuel efficiency (mpg) HEV**: 50
- **Fuel efficiency (mpg) ICE of PHEV**: 60
- **PHEV Gas ratio**: 20%

#### (US)

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<tr>
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<th>Diesel</th>
<th>HEV</th>
<th>PHEV</th>
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<td><strong>Base Car Price</strong></td>
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<td>$19,000</td>
<td>$22,000</td>
<td>$24,000</td>
<td>$25,000</td>
</tr>
<tr>
<td><strong>Battery Costs</strong></td>
<td>$ -</td>
<td>$ -</td>
<td>$1,800</td>
<td>$7,500</td>
<td>$15,000</td>
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<tr>
<td><strong>Tax Credit</strong></td>
<td>$ -</td>
<td>$ -</td>
<td>$ -</td>
<td>$2,900</td>
<td>$7,500</td>
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<td><strong>Purchase Costs</strong></td>
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<td>$19,000</td>
<td>$23,800</td>
<td>$28,600</td>
<td>$32,500</td>
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<tr>
<td><strong>Annual Fuel Costs</strong></td>
<td>$1,219</td>
<td>$1,100</td>
<td>$780</td>
<td>$130</td>
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<td><strong>Annual Electricity Costs</strong></td>
<td>$ -</td>
<td>$ -</td>
<td>$213</td>
<td>$266</td>
<td>$ -</td>
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<td><strong>Annual Maintenance</strong></td>
<td>$600</td>
<td>$600</td>
<td>$720</td>
<td>$810</td>
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<td><strong>Annual Costs</strong></td>
<td>$1,819</td>
<td>$1,700</td>
<td>$1,500</td>
<td>$1,153</td>
<td>$1,166</td>
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<td><strong>PV Total Costs</strong></td>
<td>$26,097</td>
<td>$26,568</td>
<td>$30,478</td>
<td>$33,732</td>
<td>$37,691</td>
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<tr>
<td><strong>Cost per mi</strong></td>
<td>$0.522</td>
<td>$0.531</td>
<td>$0.610</td>
<td>$0.675</td>
<td>$0.754</td>
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#### Initial and Lifetime Costs

- **PV Total Costs**
- **Cost per mi**
- **Max Battery Cost ($/KW), vs. Gasoline**
- **Max Battery Cost ($/KW), vs. Diesel**

**Source:** Credit Suisse Estimates
**Disclosure Appendix**

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