Key Statistics

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stock Price (06/24/16)</td>
<td>$6.95</td>
</tr>
<tr>
<td>52 Week High/Low</td>
<td>$12.82-$5.01</td>
</tr>
<tr>
<td>Shares Outstanding Diluted*</td>
<td>~200 MM</td>
</tr>
<tr>
<td>Public Float</td>
<td>~187 MM</td>
</tr>
<tr>
<td>Avg. Daily Vol. (3 month)</td>
<td>~5.6 MM</td>
</tr>
<tr>
<td>Market Capitalization</td>
<td>~$1.4 B</td>
</tr>
<tr>
<td>Cash &amp; Equivalents (05/10/16 Pro-forma*)</td>
<td>~$94 MM</td>
</tr>
<tr>
<td>Outstanding Debt (9% Senior Notes Due 2021 Pro-forma*)</td>
<td>$80 MM</td>
</tr>
<tr>
<td>Borrowing Base Availability (as of 06/24/16)</td>
<td>$145 MM</td>
</tr>
</tbody>
</table>

*Pro-forma for Equity closed on 5/10/16 and closing of Senior Notes, GC Acquisition and Adams County divestiture.

Sources: Company estimates. In USD
Features of the Wattenberg Field

Wattenberg Field – DJ Basin

WYOMING
NEBRASKA
COLORADO
KANSAS

PIERRE SHALE
SUSSEX (TERRY) SS
PIERRE SHALE
SHANNON (HYGIENE) SS
PIERRE SHALE
NIOBRARA “A”
NIOBRARA “B”
NIOBRARA “C”
FT HAYS LIMESTONE
CODELL SAND
CARLILE SHALE
GREENHORN LS
GRANEROS SHALE
J1 SAND
SKULL CREEK SHALE
DAKOTA SAND

Typical Depth
4300’
4800’
6800’
7100’
7600’

Pay

Sonnenberg, 2002
Synergy’s DJ Basin Acreage Position is ~121,300 Net Acres

~22,100 Net Acres in Greater Wattenberg Area

Focus on ~47,200 Net Wattenberg Fairway Acres

NE Extension Area ~ 52,000 Net Acres

Note: Offset operator acreage positions reflect approximations, are not meant to depict entire leasehold, and may contain inaccuracies.
Focus on ~47,200 Net Wattenberg Fairway Acres

~69,300 Net Acres in Wattenberg

~22,100 Net Acres in Greater Wattenberg Area

Wattenberg Fairway Area
**Current D&C Operations**

- **Bestway Pad**: 4 (~3.5 net) ML wells in production
- **Vista Pad**: 10 (~8.5 net) SL wells in flow back/early production
- **Fagerberg Pad**: 14 (~13.5 net) ML drilling
- **Evans Pad**: 22 (~15.5 net) LL wells permitted
- **Williams Pad**: 9 (~9 net) ML wells permitted

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**ML: Mid Length Lateral**
- Avg. Effective length: 6,920'
- Drill & Complete*: $3.5mm
- Drill Time (RR-RR**): 6-8 days

*assumes 2:1 Nio:Cod ratio
**includes surface casing

**LL: Long Length Lateral**
- Avg. Effective length: 9,560'
- Drill & Complete*: $4.5mm
- Drill Time (RR-RR**): 7-10 days

*assumes 2:1 Nio:Cod ratio
**includes surface casing

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**SYRG Leases**
- GOR (scf/bbl of oil)
  - > 12,000
  - 6,000 – 12,000
  - 2,000 – 6,000
  - < 2,000

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**Vista Pad**
- Drilling: Mar – July ‘16
- Completion: Aug – Nov ‘16

**Williams Pad**
- Drilling: Nov – Dec ‘16
- Completion: Jan – Mar ‘17

**Fagerberg Pad**
- Drilling: Mar – July ‘16
- Completion: Aug – Nov ‘16

**Evans (West) Pad**
- Drilling: July – Nov ‘16
- Completion: Dec ‘16 – May ‘17

**Evans (East) Pad**
- Drilling: July – Nov ‘16
- Completion: Nov ‘16 – Mar ‘17

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Please note that net well percentages are subject to change through acquisitions, pooling, trades, swaps, earning agreements, and other reversionary interests.
Estimated Well Economics for ML Lateral

Strip Price Deck | Wall Street Consensus
--- | ---
$3.5mm | 670 Mboe
6 – 8 days | 47% 52%
$2.9mm | $3.9mm

Note: The well economics presented are representative of an average Niobrara mid-length lateral well drilled and completed within the Wattenberg fairway.

WS Consensus (6/16/16): 2016 = $45.88 / 2017 = $53.88 / 2018 = $60.65 / $73.50 flat starting January 2020 for oil.
Assumed differentials: oil = $9.00 / gas = $0.25.

Well Cost (1)
EUR (2)
Drilling Days
IRR (3)
Months to Payout (3)
PV-10

(1) Well Cost estimates include all drilling and completions costs, as well as all surface and production facilities, but do not include leasehold or corporate overhead.
(2) Estimated EURs may not correspond to estimates of reserves as defined under SEC rules.
(3) Rate of return and payout estimates do not reflect lease acquisition costs or corporate, general and administrative expenses. Payout estimates calculated from first month of production.
(4) Assumes gas-to-oil price ratio of 1:20 applied against given crude oil price less above referenced diff's.
DCP Midstream & Oil Pipeline Infrastructure

- Fairway acreage fits well with existing/planned DCP infrastructure
- DCP Midstream’s Grand Parkway Phase 1 commenced in Q1 2016, Phase 2 rights of way and permitting in process
- Installation of 3rd party oil gathering systems underway
- Synergy has secured capacity under long term contracts on the White Cliffs Pipeline and on the Grand Mesa Pipeline scheduled for late 2016

**Gross Oil Volume Commitments on 8/8ths Basis**

- 6,157 Bbl/d on White Cliffs
- 5,000 Bbl/d on Grand Mesa

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**Note:**

Volume commitments outlined on this slide represent gross operated barrels, not NRI volumes.

(1) Commitment subject to completion of the Grand Mesa Pipeline and ongoing negotiations.
Production and Proved Reserves Growth

Daily Net Production

<table>
<thead>
<tr>
<th></th>
<th>FY 2014</th>
<th>FY 2015</th>
<th>Q1 03/31/16</th>
<th>2016 Est.*</th>
</tr>
</thead>
<tbody>
<tr>
<td>BOEPD</td>
<td>4,290</td>
<td>8,725</td>
<td>11,510</td>
<td>11,000-12,000</td>
</tr>
</tbody>
</table>

Proved Reserves MMBoe

- **8/31/2014**: 32 MMBoe
- **8/31/2015**: 57 MMBoe
- **12/31/2015**: 66 MMBoe

*Company 2016 Guidance does not include production from pending GC Acquisition*
2016 Estimated Capex ~$150 Million*

Drilling and Completion ~$115 Million
Land Leasing ~$30 Million
Other ~$5 Million

Source: Company Est.

*Assumes average 1 rig program for 2016. The Company has operational flexibility, and capex could be reduced to $130 million or lower depending on commodity prices and actual costs.
Financial Strategy

Maintain adequate liquidity & strong balance sheet

• Pro forma for the equity offerings, notes issuance and transaction
  o Post closing PF liquidity of ~$225 million\(^{(1)}\)
  o $145 million available on undrawn revolver
  o $80 million in outstanding debt on long-term notes

• 2016 & 2017 development plan is designed to be fully funded
  o Outspend covered by existing cash + expected revolver availability
  o Flexibility to accelerate or decelerate activity based on commodity prices

• Conservative leverage profile to preserve capital flexibility
  o PF debt / EBITDA of 0.9x based on trailing twelve months adjusted EBITDA\(^{(2)}\)
  o PF debt / capitalization of 7%

Balancing upside from increasing activity with disciplined hedging strategy

• Goal to hedge approximately half forecasted 2017 production by YE’16
  o Primarily utilizing costless collars

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(1) Reflects liquidity as of 3/31/16 adjusted for April & May equity offerings, GC acquisition, Adams County divestiture and notes issuance
(2) LTM Adj. EBITDA reflects Synergy’s 12 months ended 3/31/16 plus the trailing 12 months GC acquisition estimated EBITDA
# Management Team

<table>
<thead>
<tr>
<th>Name</th>
<th>Title</th>
<th>Experience</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lynn A. Peterson</td>
<td>Chairman, President &amp; CEO</td>
<td>Former co-founder, President and CEO of Kodiak Oil &amp; Gas, he has over 30 years of experience in executive management of oil and gas companies</td>
</tr>
<tr>
<td>James P. Henderson</td>
<td>EVP of Finance and CFO</td>
<td>More than 25 years of industry finance and management experience including Kodiak Oil &amp; Gas, Anadarko Petroleum Corp., and Western Gas Resources</td>
</tr>
<tr>
<td>Mike Eberhard</td>
<td>COO - Operations</td>
<td>Petroleum engineer with over 30 years of industry experience including management positions with Anadarko and Halliburton</td>
</tr>
<tr>
<td>Nick Spence</td>
<td>COO - Development</td>
<td>Petroleum engineer with 25 years of industry experience in operations, including the past 4 years with Anadarko in the Wattenberg Field</td>
</tr>
<tr>
<td>Craig Rasmuson</td>
<td>EVP – Business Development</td>
<td>Joined SYRG at its inception in 2008 and has supervised all of its field operations. Formerly with PDC Energy and DCP Midstream</td>
</tr>
<tr>
<td>Brant DeMuth</td>
<td>VP of Finance</td>
<td>CFA with over 30 years of financial analysis, asset management, and derivative trading experience. Former CFO of DJ Resources</td>
</tr>
<tr>
<td>Brian Macke</td>
<td>Director of Government Affairs</td>
<td>Petroleum Engineer with 35 years of industry experience in regulatory affairs, including 17 years with the Colorado Oil &amp; Gas Conservation Commission, serving as Director of the Commission for 4 years</td>
</tr>
<tr>
<td>Cathleen Osborn</td>
<td>VP and General Counsel</td>
<td>30 years of industry experience and most recently served as in house counsel for Whiting Petroleum and prior to that Kodiak Oil &amp; Gas</td>
</tr>
<tr>
<td>Jared Grenzenbach</td>
<td>VP Accounting and CAO</td>
<td>CPA with 18 years of accounting experience including over 10 years in oil and gas and 4 years with Deloitte &amp; Touche LLP</td>
</tr>
<tr>
<td>Matthew Miller</td>
<td>VP of Land</td>
<td>Landman with over 30 years experience in the industry. He was formerly with Anadarko</td>
</tr>
<tr>
<td>Tom Birmingham</td>
<td>VP of Exploration</td>
<td>Geologist with 35 years in the industry with focus on the Wattenberg Field with Anadarko, Kerr McGee and HS Resources</td>
</tr>
</tbody>
</table>
## Crude Oil and Natural Gas Hedges

<table>
<thead>
<tr>
<th>Month</th>
<th>Collar Volumes (Bbl)</th>
<th>Collar Volumes (MMBtu)</th>
<th>Collar Volumes (MMBtu)</th>
<th>Average Collar Prices (1)</th>
<th>Oil (Bbl)</th>
<th>Gas HH (MMBtu)</th>
<th>Gas CIG (MMBtu)</th>
<th>Oil (Bbl)</th>
<th>Gas HH (MMBtu)</th>
<th>Gas CIG (MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>June 1 to December 31, 2016</strong></td>
<td>293,000</td>
<td>180,000</td>
<td>700,000</td>
<td>$42.39-$62.39</td>
<td>293,000</td>
<td>180,000</td>
<td>700,000</td>
<td>$42.39-$62.39</td>
<td>293,000</td>
<td>180,000</td>
</tr>
<tr>
<td><strong>January 1 to December 31, 2017</strong></td>
<td>605,000</td>
<td>-</td>
<td>3,240,000</td>
<td>$41.98 - $63.97</td>
<td>605,000</td>
<td>-</td>
<td>3,240,000</td>
<td>$41.98 - $63.97</td>
<td>605,000</td>
<td>-</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Month</th>
<th>Put Volumes (Bbl)</th>
<th>Put Volumes (MMBtu)</th>
<th>Put Volumes (MMBtu)</th>
<th>Average Option Put Prices (1)</th>
<th>Oil (Bbl)</th>
<th>Gas HH (MMBtu)</th>
<th>Gas CIG (MMBtu)</th>
<th>Oil (Bbl)</th>
<th>Gas HH (MMBtu)</th>
<th>Gas CIG (MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>June 1 to December 31, 2016</strong></td>
<td>245,000</td>
<td>-</td>
<td>-</td>
<td>$</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>January 1 to August 31, 2017</strong></td>
<td>160,000</td>
<td>-</td>
<td>-</td>
<td>$52.50</td>
<td>160,000</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
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</tbody>
</table>

(1) Oil price is based on NYMEX WTI and gas price is based on NYMEX Henry Hub or CIG.

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**Disclosure on Derivative Instruments**

The Company has entered, or may enter in the future, into commodity derivative instruments utilizing, price swaps, collars, put or call options to reduce the effect of price changes on a portion of future oil and gas production. The Company’s commodity derivative instruments are measured at fair value and are included in the condensed balance sheet as derivative assets and liabilities.

All derivative positions are carried at their fair value on the condensed balance sheet and are marked-to-market at the end of each period. Both the unrealized and realized gains and losses resulting from the contract settlement of derivatives are recorded in the gain on derivatives line on the condensed statement of operations.

The Company has a master netting agreement on each of the individual oil and gas contracts and therefore the current asset and liability are netted on the condensed balance sheet and the non-current asset and liability are netted on the condensed balance sheet.
<table>
<thead>
<tr>
<th></th>
<th>Three months ended</th>
<th>Four months ended</th>
<th>Twelve months Ended</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted EBITDA</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net income (loss)</td>
<td>($50,500)</td>
<td>($993)</td>
<td>($122,932)</td>
</tr>
<tr>
<td>Add back:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation, depletion and amortization</td>
<td>12,078</td>
<td>14,077</td>
<td>18,776</td>
</tr>
<tr>
<td>Full cost ceiling impairment</td>
<td>44,734</td>
<td>–</td>
<td>125,230</td>
</tr>
<tr>
<td>Income tax expense (benefit)</td>
<td>–</td>
<td>(709)</td>
<td>(10,007)</td>
</tr>
<tr>
<td>Stock based compensation</td>
<td>2,519</td>
<td>1,604</td>
<td>8,431</td>
</tr>
<tr>
<td>Mark to market of commodity derivatives contracts</td>
<td>(1,680)</td>
<td>(3,461)</td>
<td>(6,482)</td>
</tr>
<tr>
<td>Total (gain) loss on commodity derivatives contracts</td>
<td>3,059</td>
<td>13,742</td>
<td>1,954</td>
</tr>
<tr>
<td>Cash settlements on commodity derivatives contracts</td>
<td>–</td>
<td>(3,498)</td>
<td>(956)</td>
</tr>
<tr>
<td>Cash premiums paid for commodity derivative contracts</td>
<td>(2)</td>
<td>15</td>
<td>(40)</td>
</tr>
<tr>
<td>Adjusted EBITDA</td>
<td>$10,208</td>
<td>$20,777</td>
<td>$13,974</td>
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