Outline Day 1

• Introduction
  – Overview of energy value chains - oil and gas systems in overall context
  – Key issues impacting global energy and trade flows – National Petroleum Council Global Oil and Gas Study
  – National Oil Companies
  – Commodity vs physical markets

• Upstream issues
  – Trends - North America, worldwide
  – Identification of key risks, uncertainties
  – Upstream investment decision considerations
  – Heavy oil resource case study - technology and optimization
Outline Day 2

• Midstream/downstream commercialization
  – Trends - North America, worldwide (oil v gas)
  – Pipeline economics and cost model
  – Refining economics and issues
  – LNG value chain
  – Gas and power business models
• Conclusions
  – Business integration models and asset/enterprise valuation

The Link Between Energy Value Chain Economics, Finance and Frameworks

Natural Gas Pipelines

McCombs School of Business: Energy Finance Program

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Pipeline Economics

• Costs associated with pipeline construction depend on many factors.
  – the cost per mile increases with the pipe size.
  • construction on land using a 12-inch pipeline costs about $300,000 per mile while using a 42-inch pipeline costs almost $1.5 million per mile.
  – costs increases if the pipeline goes through residential areas, or there are roads, highways and rivers on the way.
  – costs are dependent on location, terrain, population density, or other factors (for instance, different labor and tax laws in different countries).

Pipeline Costs

• The most important are material and labor costs - 70 to 80% of the total construction cost both onshore and offshore.
• Surveying, engineering, supervision, administration and overhead, telecommunications equipment, freight, taxes, regulatory filing fees, interest, contingencies (all covered under Miscellaneous).
• Right-of-way (R.O.W.) and damages
### Table 6.2 Estimated Pipeline Construction Costs per Mile and % of Total Onshore

<table>
<thead>
<tr>
<th>Category</th>
<th>1995-1996</th>
<th>2000-2001</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Material</td>
<td>$274,210 (31%)</td>
<td>$279,565 (21%)</td>
<td>2%</td>
</tr>
<tr>
<td>Labor</td>
<td>$422,610 (47%)</td>
<td>$571,719 (44%)</td>
<td>35%</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>$154,012 (17%)</td>
<td>$344,273 (26%)</td>
<td>124%</td>
</tr>
<tr>
<td>R.O.W. and Damages</td>
<td>$48,075 (5%)</td>
<td>$120,607 (9%)</td>
<td>151%</td>
</tr>
<tr>
<td>Total</td>
<td>$898,907</td>
<td>$1,316,164</td>
<td>38%</td>
</tr>
</tbody>
</table>

Source: Oil & Gas Journal, Pipeline Economics Survey, various issues.

### Table 6.3 Estimated Pipeline Construction Costs per Mile and % of Total Offshore

<table>
<thead>
<tr>
<th>Category</th>
<th>1995-1996</th>
<th>2000-2001</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Material</td>
<td>$684,604 (42%)</td>
<td>$413,995 (16%)</td>
<td>-40%</td>
</tr>
<tr>
<td>Labor</td>
<td>$527,619 (33%)</td>
<td>$1,537,249 (60%)</td>
<td>191%</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>$396,394 (25%)</td>
<td>$510,271 (20%)</td>
<td>29%</td>
</tr>
<tr>
<td>R.O.W. and Damages</td>
<td>$3,201 (0%)</td>
<td>$116,898 (4%)</td>
<td>3,552%</td>
</tr>
<tr>
<td>Total</td>
<td>$1,611,818</td>
<td>$2,578,413</td>
<td>60%</td>
</tr>
</tbody>
</table>

Source: Oil & Gas Journal, Pipeline Economics Survey, various issues.
Inferred Construction Cost/Mile (2004-2005)

Source: Gurfinkel, et.al., Oil & Gas Journal, November 2006, based on CEE research and FERC data.

High, Mean, Low Estimates for Large Diameter Pipelines

Source: Gurfinkel, et.al., Oil & Gas Journal, November 2006, based on CEE research and FERC data.
### Analogs

<table>
<thead>
<tr>
<th>Analogue</th>
<th>Cost &lt;millions&gt;</th>
<th>Length &lt;miles&gt;</th>
<th>Diameter &lt;inches&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>MacKenzie Valley</td>
<td>$3,500.00</td>
<td>812.5</td>
<td>30</td>
</tr>
<tr>
<td>Rockies Express System</td>
<td>$4,000.00</td>
<td>1300</td>
<td>40</td>
</tr>
<tr>
<td>Rockies Express West</td>
<td>$1,600.00</td>
<td>713</td>
<td>42</td>
</tr>
<tr>
<td>Foothills Pipe Lines Ltd.</td>
<td>$8,000.00</td>
<td>1750</td>
<td>42</td>
</tr>
<tr>
<td>Russia to Germany</td>
<td>$4,800.00</td>
<td>744</td>
<td>56</td>
</tr>
<tr>
<td>Iran to India</td>
<td>$4,200.00</td>
<td>1000</td>
<td>28</td>
</tr>
<tr>
<td>Venezuela-Colombia</td>
<td>$330.00</td>
<td>144</td>
<td>26</td>
</tr>
<tr>
<td>Great Southern</td>
<td>$23,000.00</td>
<td>5000</td>
<td>52</td>
</tr>
</tbody>
</table>

Source: Gurfinkel, et.al., Oil & Gas Journal, November 2006, based on CEE research and FERC data.

### Model Predictions vs. Reported

<table>
<thead>
<tr>
<th>Analogue</th>
<th>Reported Cost/Mile</th>
<th>Estimate Using Mean Cost Model</th>
<th>Estimate Using High Cost Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>MacKenzie Valley</td>
<td>$4,307,692.31</td>
<td>$2,503,100.00</td>
<td>$4,195,700.00</td>
</tr>
<tr>
<td>Rockies Express System</td>
<td>$3,076,923.08</td>
<td>$2,345,900.00</td>
<td>$4,824,600.00</td>
</tr>
<tr>
<td>Rockies Express West</td>
<td>$2,244,039.27</td>
<td>$3,394,460.00</td>
<td>$4,950,380.00</td>
</tr>
<tr>
<td>Foothills Pipe Lines Ltd.</td>
<td>$4,571,428.57</td>
<td>$3,394,460.00</td>
<td>$4,950,380.00</td>
</tr>
<tr>
<td>Russia to Germany</td>
<td>$6,451,612.90</td>
<td>$4,434,840.00</td>
<td>$5,820,840.00</td>
</tr>
<tr>
<td>Iran to India</td>
<td>$4,200,000.00</td>
<td>$2,354,540.00</td>
<td>$4,069,920.00</td>
</tr>
<tr>
<td>Venezuela-Colombia</td>
<td>$2,295,652.17</td>
<td>$2,205,988.00</td>
<td>$3,944,140.00</td>
</tr>
<tr>
<td>Great Southern Gas Pipeline</td>
<td>$4,600,000.00</td>
<td>$4,137,260.00</td>
<td>$5,579,280.00</td>
</tr>
</tbody>
</table>

Source: Gurfinkel, et.al., Oil & Gas Journal, November 2006, based on CEE research and FERC data.
Model vs. Analogs

Source: Gurfinkel, et al., Oil & Gas Journal, November 2006, based on CEE research and FERC data.

Alaska Expected vs. Model

(52in, $ millions excluding cost overruns)

<table>
<thead>
<tr>
<th></th>
<th>Alaska to Alberta Expected Cost</th>
<th>Alberta to Chicago Expected Cost</th>
<th>Alberta to Chicago Lower Bound</th>
<th>Total Cost Expected</th>
<th>Total Cost Lower Bound</th>
</tr>
</thead>
<tbody>
<tr>
<td>$ 11,940</td>
<td>$ 8,369</td>
<td>$ 6,206</td>
<td>$ 20,309</td>
<td>$ 18,146</td>
<td></td>
</tr>
</tbody>
</table>

Source: Gurfinkel, et al., Oil & Gas Journal, November 2006, based on CEE research and FERC data.
Maritimes & Northeast Pipeline

- Cost of $1.2 billion
- Pipeline length of 1,086 km (663 miles)
- Capacity of 530,000 MMBtu/d
- Placed into service December 1, 1999
- Rate (toll) of $1.20 per MMBtu
- Owners
  - Duke Energy: 37.5%
  - Westcoast Energy: 37.5%
  - ExxonMobil: 12.5%
  - Nova Scotia Power: 12.5%
Maritimes & Northeast Pipeline

- Debt/equity structure of 75%/25%
- Debt
  - US$521.4 million fully amortizing
  - Canadian $712.3 million with 36% balloon payment
  - All debt maturing on November 30, 2009
- Lead banks are
  - Bank of America
  - The Canadian Imperial Bank of Commerce

Maritimes & Northeast Pipeline

- M&NE was the only natural gas pipeline linking the Sable fields to natural gas markets
  - Because of its importance, Mobil agreed to capacity Backstop Agreements
- Backstop Agreements by Mobil
  - Mobil agreed to purchase approximately 175 MMBtu/d of unsubscribed firm capacity in both Canada and U.S. for 20 years
- Due to the Backstop Agreements, there was no cross default between the physical assets or partnership interests in the U.S. and Canada
**Pipeline Commercial Framework, II**

**Alliance Pipeline System: Unlocking Remote Supply for Established Market**

**Alliance Pipeline**

- Cost of $3.1 billion
- Largest project financed in North America
- Pipeline length of 1,860 miles
- Capacity of 1,600,000 MMBtu/d
- Placed into service December 1, 2000
- Rates (tolls)
  - $0.82 per MMBtu for rich gas
  - $0.73 per MMBtu for lean gas
Alliance Pipeline

• Owners
  – Fort Chicago Energy Partners: 26%
  – Westcoast Energy: 23.6%
  – Enbridge Inc.: 21.4%
  – The Williams Companies, Inc.: 14.6%
  – El Paso Corporation (The Coastal Corporation): 14.4%

• Debt/equity structure of 70%/30%
• Debt
  – US$961.5 million with balloon payment
  – Canadian $1.6 billion with balloon payment
  – All debt maturing on December 21, 2008
• Lead banks were
  – Bank of Montreal
  – The Bank of Nova Scotia
  – The Chase Manhattan Bank
  – Royal Bank of Scotland
The Link Between Energy Value Chain Economics, Finance and Frameworks

LNG

World Natural Gas Supply (Trade)

1999 (Total Consumption 2,293 BCM; 81 TCF)

- Domestic Production: 80%
- International Pipeline Trade: 15%
- LNG: 5%

2005 (Total Consumption 2,750 BCM; 97 TCF)

- Domestic Production: 74%
- International Pipeline Trade: 19%
- LNG: 7%

Sources: BP Annual Statistical Review, 2006
## Liquefaction

Global Liquefaction Plant Capacity (mtpa) as of March, 2007

<table>
<thead>
<tr>
<th>Region</th>
<th>Operating</th>
<th>Under Construction</th>
<th>Planned</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pacific Basin</td>
<td>68.9</td>
<td>23</td>
<td>77</td>
<td>168.9</td>
</tr>
<tr>
<td>Middle East</td>
<td>36.3</td>
<td>56.7</td>
<td>43.8</td>
<td>136.8</td>
</tr>
<tr>
<td>Atlantic Basin</td>
<td>65.5</td>
<td>11.6</td>
<td>164.1</td>
<td>241.2</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>170.7</strong></td>
<td><strong>91.3</strong></td>
<td><strong>284.9</strong></td>
<td><strong>546.9</strong></td>
</tr>
</tbody>
</table>

Actual production 2006: 168 mt

*Sources: Various industry sources and trade publications*

---

## Summary of Global LNG Ships in Operation & on Order (as of March ’07)

<table>
<thead>
<tr>
<th>Ship Capacity (m³)</th>
<th>Ships in Operation</th>
<th>Ships on Order</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>18,000 to 50,000</td>
<td>20</td>
<td>1</td>
<td>21</td>
</tr>
<tr>
<td>51,000 to 120,000</td>
<td>15</td>
<td>2</td>
<td>17</td>
</tr>
<tr>
<td>&gt;120,000</td>
<td>189</td>
<td>97</td>
<td>286</td>
</tr>
<tr>
<td>209,000 to 270,000</td>
<td>-</td>
<td>45</td>
<td>45</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>224</strong></td>
<td><strong>145</strong></td>
<td><strong>369</strong></td>
</tr>
</tbody>
</table>

*Sources: Various industry sources and trade publications*
### Global Regasification Terminals by Regions (as of March 2007)

<table>
<thead>
<tr>
<th>Region</th>
<th>Operating Terminals</th>
<th>Terminals Under Construction</th>
<th>Approved Terminals Not Under Construction</th>
<th>Planned or Proposed Terminals</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Asia-Pacific</td>
<td>36</td>
<td>7***</td>
<td>22**</td>
<td></td>
<td>65</td>
</tr>
<tr>
<td>USA/NA</td>
<td>7*</td>
<td>6</td>
<td>11**</td>
<td>50***</td>
<td>74</td>
</tr>
<tr>
<td>Latin America</td>
<td>1</td>
<td>1</td>
<td>4</td>
<td></td>
<td>6</td>
</tr>
<tr>
<td>Europe</td>
<td>14**</td>
<td>8**</td>
<td>23**</td>
<td></td>
<td>45</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>58</strong></td>
<td><strong>22</strong></td>
<td><strong>11</strong></td>
<td><strong>99+</strong></td>
<td><strong>190+</strong></td>
</tr>
</tbody>
</table>

*Includes Excelerate's offshore Gulf Gateway
**Includes other offshore designs in the US and Europe and expansions to existing and new terminals

Sources: Various industry sources and trade publications; FERC for North America

---

### LNG Value Chain Costs

<table>
<thead>
<tr>
<th>EXPLORATION &amp; PRODUCTION</th>
<th>LIQUEFACTION</th>
<th>SHIPPING</th>
<th>REGASIFICATION &amp; STORAGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.5-$1.0/MMBtu</td>
<td>$0.8-$1.20/MMBtu</td>
<td>$0.4-$1.0/MMBtu</td>
<td>$0.3-$0.5/MMBtu</td>
</tr>
</tbody>
</table>

**TOTAL = $2.00 - $3.70**

TOTAL (with cost escalation) = $2.60 - $4.80

*Sources: Industry (estimates exclude some O&M and tax costs)*
Cost Were Declining; Are Rising Again (Excludes Feedstock)

Will larger scale yield competitive unit costs?

<table>
<thead>
<tr>
<th>Year</th>
<th>Total, 1980s</th>
<th>Liquefaction</th>
<th>Shipping</th>
<th>Total, 2000s</th>
<th>Liquefaction</th>
<th>Regas and Storage</th>
<th>Total, 2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>1980s</td>
<td>2.5</td>
<td></td>
<td></td>
<td>1.8</td>
<td></td>
<td></td>
<td>2.58</td>
</tr>
<tr>
<td>2006</td>
<td>0.5</td>
<td>0.1</td>
<td>0.1</td>
<td>0.3</td>
<td>0.28</td>
<td>0.2</td>
<td></td>
</tr>
</tbody>
</table>

Sources: El Paso, Pickering Energy Partners; other industry sources, CEE

New LNG Contract Trend

<table>
<thead>
<tr>
<th>Example Project</th>
<th>Old</th>
<th>New</th>
</tr>
</thead>
<tbody>
<tr>
<td>Australia - N.W. Shelf 1989</td>
<td>Sold To: Japan</td>
<td>Trinidad - Atlantic LNG 1999</td>
</tr>
<tr>
<td>Sold with: High CAPEX</td>
<td>Built with: Oil-indexed pricing</td>
<td>US</td>
</tr>
<tr>
<td>Sold through: Oil-indexed pricing</td>
<td>Yielding: Low risk/Low return</td>
<td>Low CAPEX</td>
</tr>
<tr>
<td>Yielding: Low risk/Low return</td>
<td>New: Flexible Terms</td>
<td>High risk/High return</td>
</tr>
</tbody>
</table>

Source: Company Data, Deutsche Bank estimates
Changing Nature of LNG Trade

• Shift from long-term to short-term contracts
• Increasing spot market
  – Not all of the upstream volumes are tied to long-term contracts
  – Increasing number of tankers not tied to long-term contracts
  – Gas-to-gas competition v oil-indexed pricing

Traditional LNG Business Model

• Pricing and volume terms — sustain project cooperation incentives
  – isolated markets have no gas-on-gas competition, need indexed pricing
  – oil-indexed pricing put value risk on seller
  – rigid buyers’ lifting commitment (secured by TOP obligations) put market volume risk on buyer
• Joint commitment of new production, shipping and import facilities
• No free capacity through the chain for flexible trading

Source: BG
Traditional LNG Business Model

- The classic model has been hugely successful for exporters and importers alike in the Far East and Europe
- One notable exception was the U.S. were the whole industry fell flat on its face
  - Mothballed terminals and redundant ships
- U.S. developers did not follow the first rule
  - Remote reserves to a remote market
    - The UK went through this cycle to an extent
    - Regulation had distorted pricing in the market
    - Liberalization saw prices tumble to true economic costs

Source: BG

LNG Trade

- Still requires long-term committed off take, but some conditions provide more flexibility
- Increasing trend for LNG buyers to participate in the LNG plant equity: risks and forwards
- Increasing trends for reserves owners to participate down the value chain (e.g. Qatargas II)
- Increased tendency for liquefaction plants to have surplus capacity (available for spot sales) and for proprietary control of receiving terminal capacity
- Impact on the financing of new LNG projects

New LNG Trade

• New GSPAs demonstrate the buyers’ emphasis on flexibility
• Commitment terms: 15 to 20 years with pricing provisions possibly valid for only 3 to 5 years; divergence from crude oil based formulas
• Greater amount of flexibility with the take-or-pay requirements of less than 100% of the output capacity
• New GSPAs may include short-term, 5-10 year contracts
  - Take-or-pay features still prevalent
  - Seasonal contracts
  - Tradable cargos
• Selling to “the market” instead of AAA utility


LNG Pricing

U.S.
• Generally LNG prices are linked to the prices of Henry Hub. Prices adjustment is made depending on the location of the LNG terminal
• Importers face high price volatility

Asia
• LNG prices is normally indexed to crude oil prices. In Japan, LNG prices are based on a basket of crude oils, called the Japanese Crude Cocktail (JCC).
• LNG prices are generally higher than elsewhere in the world.
• China is breaking the trend.

Europe
• LNG prices are predominantly linked to fuel oil prices and light oil. In some cases, LNG prices are linked to a basket prices of fuel oil, light oil and coal.
• Recent development of LNG pricing includes new indices such as electricity pool prices. LNG prices is also starting to be linked to natural gas spot and futures prices.
  - Contract between Trinidad and Tobago and Spain’s Gas Natural
• Lower prices; lower volatility.

**Natural Gas Pricing Points**


- Henry Hub
- AECO
- NBP
- Zeebrugge
- Dutch TTF

Sources: World Gas Intelligence

**LNG Commercial Efficiencies**

- Europe, Asia markets paid premiums over Henry Hub to attract cargos during Winter 2005-2006
- HH discount to Asia, rough par with Europe
- HH premium to Europe

Sources: U.S. EIA
Price Convergence?
Oil indexed LNG v. Henry Hub, Europe, Japan

Sources: BP, GasMatters, NYMEX

Correlation between LNG Price and Crude Oil Price

Jung, Yonghun Ph.D, Asia Pacific Energy Research Centre, Tokyo, An Outlook for Natural Gas Market in the APEC Region, Tokyo, 2003
LNG Pricing in Japan: Will JCC Stick?

**Price Formula**

\[ P = 0.1485 \times \text{JCC} + \alpha \]

- **P**: LNG Price in $/MMBtu
- **JCC** (Japan Crude Cocktail): CIF price of a basket of crude oils into Japan in $/bbl
- **\alpha**: a constant which is project specific. Around 90 cents/MMBtu for CIF sales

**An example: LNG Price formula for Chubu Electric Company and Qatar**

\[ P = 0.1485 \times \text{JCC} + 0.8675 + S \]

- **P**: LNG Price in $/MMBtu
- **S**: S changes depending on the level of JCC.
  - JCC is in the range of $23.5 to $29.0 — \( S = (\text{JCC}-23.5)/(23.5-29.0) \)
  - JCC is in the range of $16.5 to $23.5 — \( S = 0 \)
  - JCC is in the range of $11.0 to $16.5 — \( S = (16.5-\text{JCC})/(16.5-11.0) \)

**Source**: Middle East Economic Survey (2001)

Presented in Jung, Yonghun Ph.D, Asia Pacific Energy Research Centre, Tokyo, An Outlook for Natural Gas Market in the APEC Region, Tokyo, 2003

---

**LNG Pricing**

**The Netback Market Value Concept**

- Netback = Delivered price of cheapest alternative fuel to the customer (including any taxes) adjusted for any differences in efficiency or in the cost of meeting environmental standards/limits;
  - Minus cost of transporting gas from the beach or border to the customer;
  - Minus cost of storing gas to meeting the customer’s seasonal or daily demand fluctuations;
  - Minus any gas taxes.

Jung, Yonghun Ph.D, Asia Pacific Energy Research Centre, Tokyo, An Outlook for Natural Gas Market in the APEC Region, Tokyo, 2003
Considerations for advanced markets

- Where to build a power plant?
  - Laws & regulations, market potential, etc.

- Which kind of plant to build?
  - Fuel costs, load curves, market design, env’l regulations, etc.

- How to finance it?
  - Market conditions, risks, credit, etc.
Variations in load curve during the day are crucial for running power plants:

- Some plants are better suited for base load (e.g., coal and nuclear)
- Others are better for peak load, also known as peaking units (e.g., some gas-fired plants)
Capital Costs

Source: Kyoto Report - 1998 Energy Information Administration (EIA)

Fixed & Variable O&M

Variable Cost

Fixed Cost

Economics & Technology of the Crude Oil, Natural Gas and LNG Value Chains - 47 -
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**Heat Rate**

Source: Kyoto Report - 1998 Energy Information Administration (EIA)

<table>
<thead>
<tr>
<th>Source</th>
<th>Heat Rate (Btu per kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Municipal Solid Waste</td>
<td>16,000</td>
</tr>
<tr>
<td>Combustion Turbine (Conventional)</td>
<td>11,900</td>
</tr>
<tr>
<td>Natural Gas Stream</td>
<td>10,400</td>
</tr>
<tr>
<td>Oil/Gas Stream</td>
<td>9,700</td>
</tr>
<tr>
<td>Biomass</td>
<td>9,585</td>
</tr>
<tr>
<td>Advanced Coal</td>
<td>9,500</td>
</tr>
<tr>
<td>Combined-Cycle (Advanced)</td>
<td>9,417</td>
</tr>
<tr>
<td>Combined-Cycle (Conventional)</td>
<td>8,685</td>
</tr>
<tr>
<td>Fuel Cell</td>
<td>8,030</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td>6,985</td>
</tr>
<tr>
<td>Wind</td>
<td>6,000</td>
</tr>
<tr>
<td>Total Petroleum</td>
<td>5,2391</td>
</tr>
</tbody>
</table>

**Carbon Emissions**

<table>
<thead>
<tr>
<th>Source</th>
<th>Carbon Emissions (Pounds per MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pulverized Coal</td>
<td>519</td>
</tr>
<tr>
<td>Advanced Coal</td>
<td>417</td>
</tr>
<tr>
<td>Oil/Gas Stream</td>
<td>330</td>
</tr>
<tr>
<td>Biomass</td>
<td>206</td>
</tr>
<tr>
<td>Combined Cycle (Conventional)</td>
<td>250</td>
</tr>
<tr>
<td>Combined Cycle (Advanced)</td>
<td>249</td>
</tr>
<tr>
<td>Fuel Cell</td>
<td>198</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td>145</td>
</tr>
<tr>
<td>Wind</td>
<td>0</td>
</tr>
<tr>
<td>Total Petroleum</td>
<td>0</td>
</tr>
</tbody>
</table>

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Source: The Cost of Generating Electricity, a study carried out by PB Power for the Royal Academy of Engineering, March 2004.

**Figure 1.1** – Cost of generating electricity (pence per kWh) with no cost of CO₂ emissions included.

**Figure 1.2** – Effect of a 20% change in fuel price on the cost of generating electricity.

Source: The Cost of Generating Electricity, a study carried out by PB Power for the Royal Academy of Engineering, March 2004.
### Capital Costs of Different Generation Technologies

<table>
<thead>
<tr>
<th>Technology</th>
<th>Coal</th>
<th>Natural Gas</th>
<th>Nuclear</th>
<th>Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$1,000-</td>
<td>$400-$800</td>
<td>$1,000-</td>
<td>$1,000-</td>
</tr>
<tr>
<td></td>
<td>$1,500 per</td>
<td>per kWe</td>
<td>$2,000 per</td>
<td>$2,000 per</td>
</tr>
<tr>
<td></td>
<td>kWe</td>
<td></td>
<td>kWe</td>
<td>kWe</td>
</tr>
</tbody>
</table>

Source: *Projected Costs of Generating Electricity -- 2005 Update*, by IEA and NEA

---

**Figure 1.3 – Cost of generating electricity with respect to carbon dioxide emission costs. (Zero to £30 per tonne)**

### Levelized Costs of Different Generation Technologies at 5% Discount

<table>
<thead>
<tr>
<th>Coal</th>
<th>Natural Gas</th>
<th>Nuclear</th>
<th>Wind</th>
<th>Micro Hydro</th>
<th>Solar</th>
<th>CHP</th>
</tr>
</thead>
<tbody>
<tr>
<td>$25-50</td>
<td>$37-60</td>
<td>$21-31</td>
<td>$35-95</td>
<td>$40-80</td>
<td>$150</td>
<td>$25-65</td>
</tr>
<tr>
<td>per MWh</td>
<td>per MWh</td>
<td>per MWh</td>
<td>per MWh</td>
<td>per MWh</td>
<td>(24% avail)</td>
<td>per MWh</td>
</tr>
<tr>
<td>Inv 33%</td>
<td>Inv &lt;15%</td>
<td>Inv 50%</td>
<td>O&amp;M 13-40%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>O&amp;M 20%</td>
<td>O&amp;M 10%</td>
<td>O&amp;M 30%</td>
<td>Fuel 20%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel 45%</td>
<td></td>
<td></td>
<td>O&amp;M</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Natural gas price range of $3.5-$4.5 per MMBtu

Source: Projected Costs of Generating Electricity -- 2005 Update, by IEA and NEA

---

### Levelized Costs of Different Generation Technologies at 10% Discount

<table>
<thead>
<tr>
<th>Coal</th>
<th>Natural Gas</th>
<th>Nuclear</th>
<th>Wind</th>
<th>Micro Hydro</th>
<th>Solar</th>
<th>CHP</th>
</tr>
</thead>
<tbody>
<tr>
<td>$35-60</td>
<td>$40-63</td>
<td>$30-50</td>
<td>$45-140</td>
<td>$65-100</td>
<td>$200</td>
<td>$30-70</td>
</tr>
<tr>
<td>per MWh</td>
<td>per MWh</td>
<td>per MWh</td>
<td>per MWh</td>
<td>per MWh</td>
<td>(24% avail)</td>
<td>per MWh</td>
</tr>
<tr>
<td>Inv 50%</td>
<td>Inv 20%</td>
<td>Inv 70%</td>
<td>O&amp;M 13-40%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>O&amp;M 15%</td>
<td>O&amp;M 7%</td>
<td>O&amp;M 20%</td>
<td>Fuel 10%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel 35%</td>
<td></td>
<td></td>
<td>O&amp;M</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Natural gas price range of $3.5-$4.5 per MMBtu

Source: Projected Costs of Generating Electricity -- 2005 Update, by IEA and NEA
Figure 3.1 – Specific overnight construction costs of coal-fired power plants (USD/kWe)

USD/kWe

Source: Projected Costs of Generating Electricity -- 2005 Update, by IEA and NEA

Figure 3.3 – Levelised costs of coal generated electricity at 10% discount rate (USD/MWh)

Source: Projected Costs of Generating Electricity -- 2005 Update, by IEA and NEA
Figure 3.6 – Levelised costs of gas generated electricity at 10% discount rate (USD/MWh)

Figure 3.4 – Specific overnight construction costs of gas-fired power plants (USD/kWe)

Source: Projected Costs of Generating Electricity – 2005 Update, by IEA and NEA
Figure 3.9 – Levelised costs of nuclear generated electricity at 10% discount rate (USD/MWh)

Source: Projected Costs of Generating Electricity – 2005 Update, by IEA and NEA

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Figure 3.7 – Specific overnight construction costs of nuclear power plants (USD/kWe)

Source: Projected Costs of Generating Electricity – 2005 Update, by IEA and NEA

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Stable Demand, Cyclical Supply

Source: NERC, RDI NewGen, NEG analysis

Change in Reserve Margins in Reformed Markets

<table>
<thead>
<tr>
<th></th>
<th>UK</th>
<th>NOR</th>
<th>SWE</th>
<th>VIC</th>
<th>NSW</th>
<th>CA</th>
<th>PJM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reform-2000</td>
<td>0</td>
<td>-2</td>
<td>0</td>
<td>-24</td>
<td>-13</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>5-yr avg pre-reform v avg (reform-2000)</td>
<td>5</td>
<td>-3</td>
<td>-5</td>
<td>-16</td>
<td>-7</td>
<td>-7.5</td>
<td>-3</td>
</tr>
</tbody>
</table>

Generation Investment Needs

- Industry restructuring will impact project economics:
  - Where to build a power plant?
    - Laws & regulations, market potential, etc.
  - Which kind of plant to build?
    - Fuel costs, load curves, env'l regs, etc.
  - How to finance it?
    - Market conditions, PPAs, etc.

Merchant Generation

- With restructuring and competition, power prices have become more volatile
- Volatility implies price risk
- Risk requires risk management (e.g., simple hedging)
- Merchant plants and traders/marketers create new products to manage risk (e.g., options)
- These products include a “risk premium”
Competitive Markets

• Erode excess capacity ➔ lower reserve margins ➔ increase risk to the system reliability
• How to balance the public good (desired level of reliability) with private investor requirements (a rate of return acceptable to shareholders)
• Regulatory risk

Resource Adequacy

• In competitive markets, investors have to recover their costs through market prices not through COS regulation.
• In this environment, there are basically two options to ensure resource adequacy:
  1. An energy-only market.
  2. Reserve requirement based approaches:
     a. An energy market + a capacity requirement (which is almost equivalent to an energy-only market if penalties are high enough).
     b. An energy market + a capacity market (may also involve a capacity requirement).
     c. An energy market + a capacity payment.
### Different Approaches

<table>
<thead>
<tr>
<th>Country</th>
<th>Capacity Payments</th>
<th>Capacity Markets</th>
<th>Alternative Approach</th>
</tr>
</thead>
<tbody>
<tr>
<td>Argentina</td>
<td>Fixed</td>
<td>In 2000, capacity markets</td>
<td></td>
</tr>
<tr>
<td>Australia</td>
<td>No</td>
<td>No</td>
<td>Obligations to ensure supply (Victoria) Energy-only market</td>
</tr>
<tr>
<td>Chile</td>
<td>Yes</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Colombia</td>
<td>Yes</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Norway</td>
<td>No</td>
<td>No</td>
<td>Direct ownership of some peaking plants</td>
</tr>
<tr>
<td>New Zealand</td>
<td>No</td>
<td>No</td>
<td>Energy-only market</td>
</tr>
<tr>
<td>Peru</td>
<td>Yes</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Spain</td>
<td>Fixed</td>
<td>Bilateral contracts</td>
<td></td>
</tr>
<tr>
<td>Sweden</td>
<td>No</td>
<td>No</td>
<td>Direct ownership of some peaking plants by transmission co.</td>
</tr>
<tr>
<td>UK</td>
<td>LOLP method until Oct 2000</td>
<td>No</td>
<td>Since Oct 2000, no more separate payments</td>
</tr>
<tr>
<td>US</td>
<td>No</td>
<td>Some (PJM, NEPOOL)</td>
<td>Capacity requirements</td>
</tr>
</tbody>
</table>
Transmission Issues

• Integrated utility
  – France, Japan

• Transmission company (no generation)
  – Majority of OECD countries

• Independent system operator (no generation & no transmission ownership)
  – US states, Italy

Putting It All Together

The Link Between Energy Value Chain Economics, Finance and Frameworks and Project Management:
Natural Gas Case
Building the Natural Gas Factory

**UPSTREAM**
Exploration and Production (E&P)

**MIDSTREAM**
Processing
Storage
Pipeline Transportation
LNG
Liquefaction
Shipping
Re-gasification

**DOWNSTREAM**
Distribution and End Use
Residential
Commercial
Industrial
Power
Generation
Transmission
Distribution to End Use

**Investor Goals**
Commercialize natural gas production, by:
- Increasing diversity of midstream options
- Gaining access to downstream participation where supported by markets (“power the world with gas”)
- Export

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**Project Finance and Project Development**

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Delayed Execution Erodes Value

Erosion of Project Value through Delayed Execution

Value Creation

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Optionality</th>
<th>Deliverability</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Conversion of fuel to electricity</td>
<td>• Electricity values vary by time and duration of delivery</td>
<td>• Greater value by packaging, time, flexibility</td>
</tr>
<tr>
<td>• Principal value in regulated environment</td>
<td>• Operating characteristics: ramp rates, turndown capability, fuel switching, peaking</td>
<td>• Major feature in deregulated markets</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Not important in regulated environment as market is known</td>
</tr>
</tbody>
</table>
Prices & Optionality

• Correlation between gas and power prices is high at 0.7
• But it is delayed, probably due to gas storage and hedging
• Three types of gas-fired generation:
  – Simple-cycle
  – Combined cycle
  – Peaking

Prices & Optionality

• Which one to run and when depends on:
  – Heat rate
  – Load curve
  – Ramp rate
  – Gas price
• Virtually all gas-fired generation have the capability to follow load (i.e., optionality)
• But, financing may require certain amount of long-term commitment
• The rest can be secured by options contracts
Spark Spread

- Spark spread ($/MWh) =
  - Power Price ($/MWh)
  - [Plant Heat Rate (Btu/MWh) x Gas Price ($/Btu)]
  - O&M Cost ($/MWh)

Problem: How Will Natural Gas Basis be Impacted by New Pipes and LNG?