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Natural Gas Value Chain: Pipeline Transportation

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

Estimated Pipeline Construction Costs per Mile and % of Total Onshore			
	1995-1996	**2000-2001**	**% Change**
Material	$274,210 (31%)	$279,565 (21%)	2%
Labor	$422,610 (47%)	$571,719 (44%)	35%
Miscellaneous	$154,012 (17%)	$344,273 (26%)	124%
R.O.W. and Damages	$48,075 (5%)	$120,607 (9%)	151%
Total	**$898,907**	**$1,316,164**	**38%**
Source: Oil & Gas Journal, Pipeline Economics Survey, various issues.			

Estimated Pipeline Construction Costs per Mile and % of Total Offshore			
	1995-1996	2000-2001	% Change
Material	$684,604 (42%)	$413,995 (16%)	-40%
Labor	$527,619 (33%)	$1,537,249 (60%)	191%
Miscellaneous	$396,394 (25%)	$510,271 (20%)	29%
R.O.W. and Damages	$3,201 (0%)	$116,898 (4%)	3,552%
Total	**$1,611,818**	**$2,578,413**	60%
Source: Oil & Gas Journal, Pipeline Economics Survey, various issues.			

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Natural Gas Pipeline Projects

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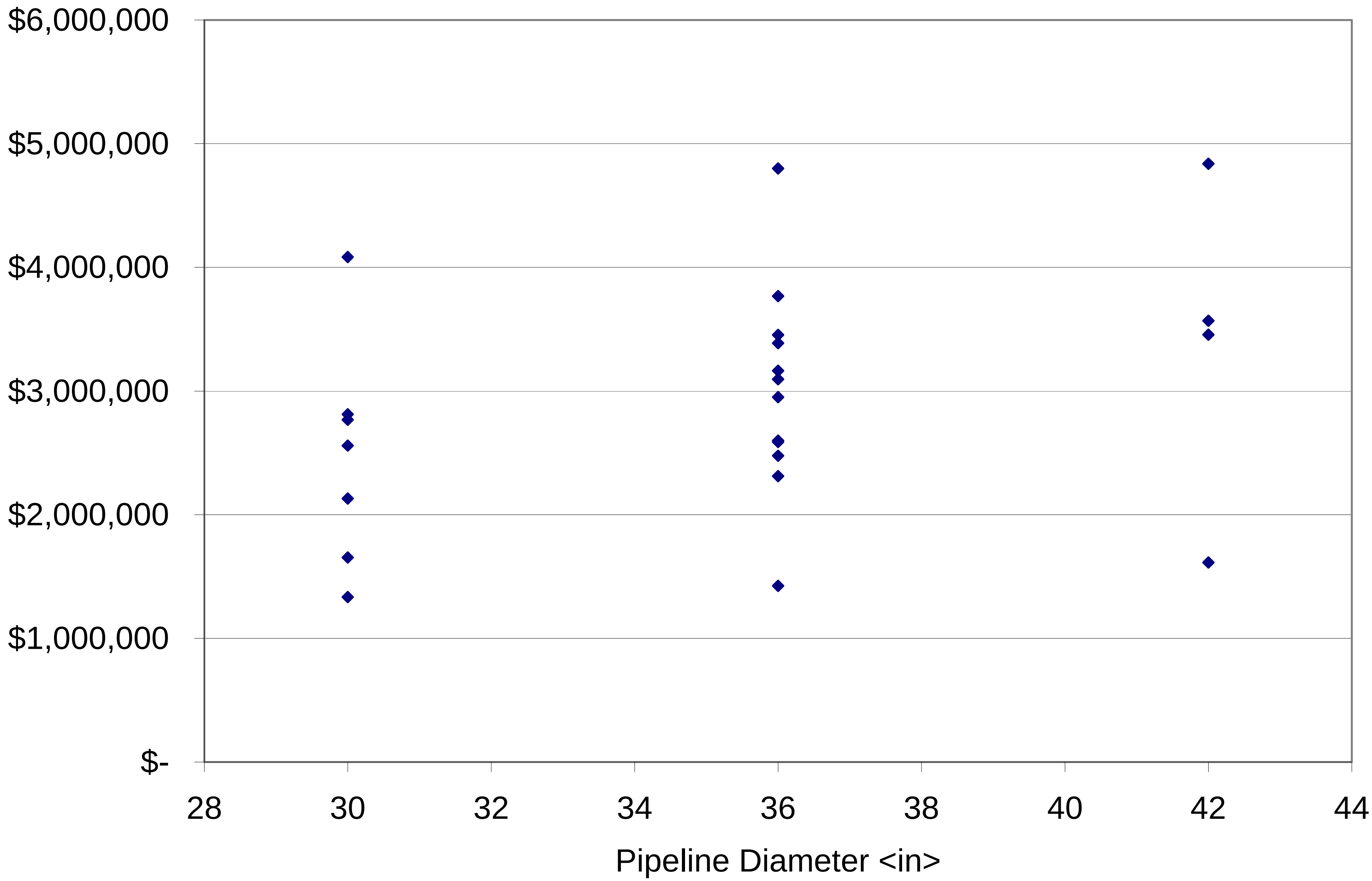
Onshore Natural Gas Pipelines 2005-2006

Diameter <in>	State	Length <miles>	Total Costs	Calculated $/mile
30	Pennsylvania	2.00	$ 5,536,000.00	$ 2,768,000.00
30	Wisconsin	3.20	$ 5,293,970.00	$ 1,654,365.63
30	Wisconsin	3.78	$ 8,050,000.00	$ 2,129,629.63
30	Pennsylvania	4.00	$ 11,247,000.00	$ 2,811,750.00
30	California	6.40	$ 8,534,000.00	$ 1,333,437.50
30	NewYork	8.80	$ 35,924,810.00	$ 4,082,364.77
30	Georgia	9.85	$ 25,194,222.00	$ 2,557,789.04
36	Louisiana	3.00	$ 10,359,476.00	$ 3,453,158.67
36	Washington	11.89	$ 57,057,798.00	$ 4,798,805.55
36	Louisiana	12.00	$ 31,070,508.00	$ 2,589,209.00
36	Washington	22.43	$ 70,976,850.00	$ 3,164,371.38
36	Washington	22.50	$ 84,782,091.00	$ 3,768,092.93
36	Texas	25.00	$ 61,918,000.00	$ 2,476,720.00
36	Washington	26.68	$ 82,596,091.00	$ 3,095,805.51
36	Texas	27.07	$ 62,582,000.00	$ 2,311,858.15
36	Maryland	47.00	$ 159,178,294.00	$ 3,386,772.21
36	Texas-Louisiana	70.00	$ 206,523,594.00	$ 2,950,337.06
36	Colorado	136.00	$ 193,747,000.00	$ 1,424,610.29
36	Texas	108.00	$ 280,595,710.00	$ 2,598,108.43
42	Louisiana	0.94	$ 3,354,090.00	$ 3,568,180.85
42	Louisiana	63.75	$ 220,251,910.00	$ 3,454,931.92
42	Louisiana	163.70	$ 791,833,000.00	$ 4,837,098.35
42	Colorado	191.00	$ 307,940,000.00	$ 1,612,251.31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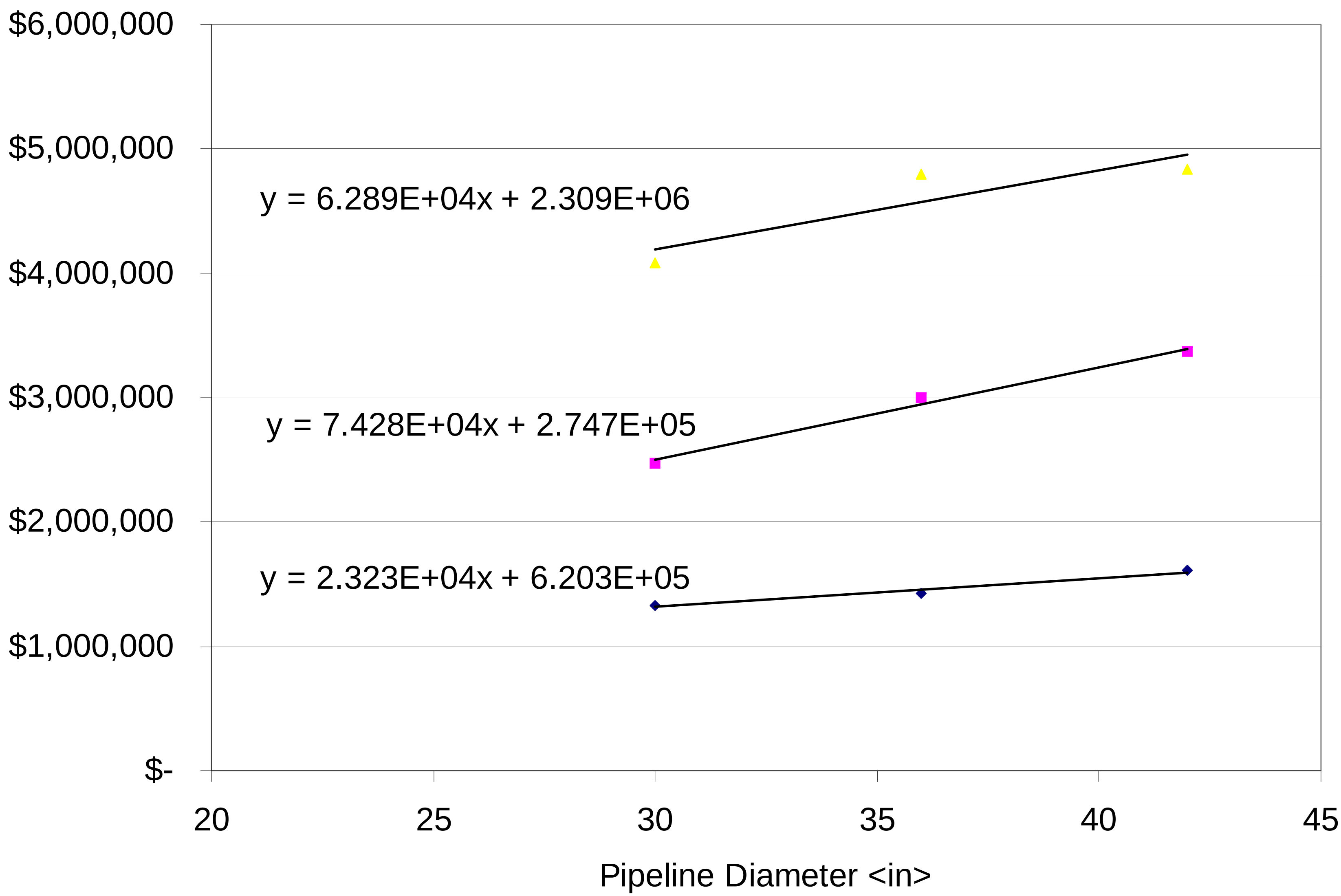
Pipeline Diameter <in>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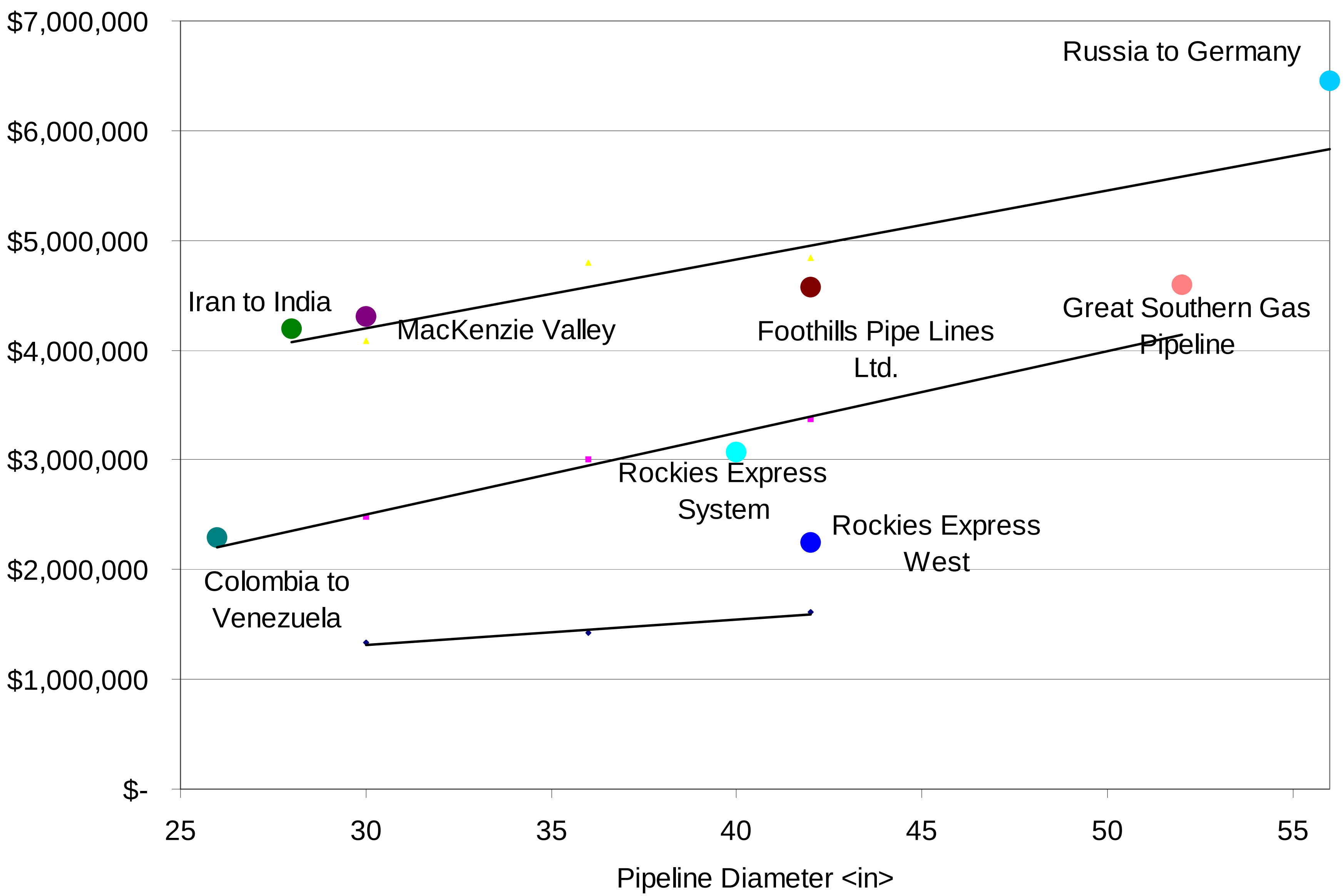
Pipeline Diameter <in>

Large Pipelines Announced in 2006

Analogue	Cost <Millions>	Length <miles>	Diameter <inches>
MacKenzie Valley	$ 3,500.00	812.5	30
Rockies Express System	$ 4,000.00	1300	40
Rockies Express West	$ 1,600.00	713	42
Foothills Pipe Lines Ltd.	$ 8,000.00	1750	42
Russia to Germany	$ 4,800.00	744	56
Iran to India	$ 4,200.00	1000	28
Venezuela-Colombia	$ 330.00	144	26
Great Southern Gas Pipeline	$ 23,000.00	5000	52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Pipeline Diameter <in>
Russia to Germany
Iran to India
MacKenzie Valley
Foothills Pipe Lines Ltd.
Great Southern Gas Pipeline
Rockies Express System
Rockies Express West
Colombia to Venezuela

Sample Calculation – WAGP

	Length <miles>	Diameter <in>	Cost of Pipeline International Pipeline per mile	Cost of Pipeline <Billions>
High Cost	400	24	$ 3,818,360	$ 1.53
Mean Cost			$ 2,057,420	$ 0.82
Low Cost			$ 1,177,820	$ 0.47

Sample Calculation – Colombia-Venezuela

	Length <miles>	Diameter <in>	Cost of Pipeline International Pipeline per mile	Cost of Pipeline <Billions>
High Cost	144	26	$ 3,944,140	$ 0.57
Mean Cost			$ 2,205,980	$ 0.32
Low Cost			$ 1,224,280	$ 0.18

- When first announced: $210 Million
- When construction started: $330 Million
- When finished: $467 Million (no compression)

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Natural Gas Value Chain: LDC Development

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Case Study:
Turkish natural gas market

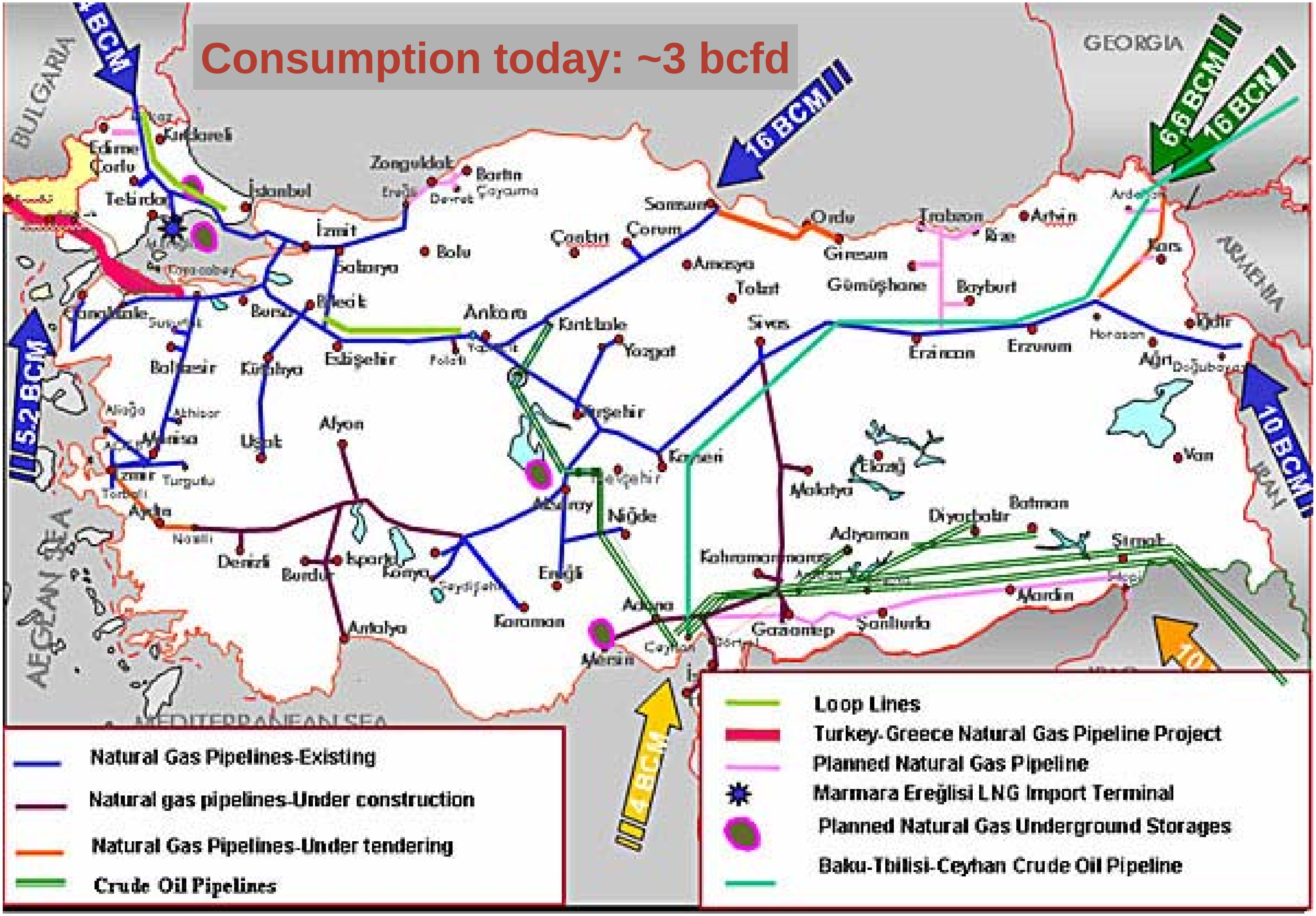
History of natural gas in Turkey

- Mid 1980s: decision to import gas from the Soviet Union to
  - Diversify fuel supplies
  - Address urban air pollution
- In 1986-7, state pipeline company, BOTAS (founded in 1974 for oil imports from Iraq), started
  - building transmission lines & distribution systems in major cities with municipalities
  - entering into import agreements
- BOTAS also built an LNG import terminal
- Consumption increased from 50 MMscfd in 1987 1.4 bcfd in 2000

History of natural gas in Turkey (cont'd)

- Natural Gas Market Law in April 2001
  - allows for private participation import, export, transmission, distribution, storage, etc.
  - calls for unbundling of BOTAS & transfer of import agreements
- The regulator created with the Electricity Market Law (February 2001) is given the responsibility to regulate natural gas
- Law amended twice in July 2003 and June 2005
- By early 2007, 53 distribution licenses issued

Consumption today: ~3 bcfd



General Requirements

- Qualified companies bid on distribution tariff
  - 3 lowest offer further discounts
  - Lowest distribution tariff wins bid (fixed for the first 8 years)
- Must start construction in 6 months
- Must start gas delivery in 18 months
- Must connect everyone in 5 years
- 30-year exclusive franchise to distribute
  - Customers consuming >15 million cm per year are free to chose supplier during first 5 years; amount to decline per EU regulations in later years

Prequalification of Bidders

- financial viability - equity, balance sheets and income statements and documents and letters of intent showing how the investment shall be financed
- experience of the bidder or the firms which will provide design, construction and operation services to the bidder, in the natural gas sector and other sectors.

Licensing rounds

- 53 franchises have been licensed
- 11 more at different stages of bidding or licensing
- In early 2006, for 3 regions, more than one company bid “0” cent/kWh; they started bidding down connection fees → in 2 of the regions, the winners bid $5 per customer (the third one bid $163 per customer)

Case study – City of Erzurum

- ~375,000 residents
- Average January temperature -11°C
- 81 active industrial plants
  - mostly small to medium enterprises
  - 40 non-operational
- New industrial park
- Mining opportunities
- $1.2 billion of GDP

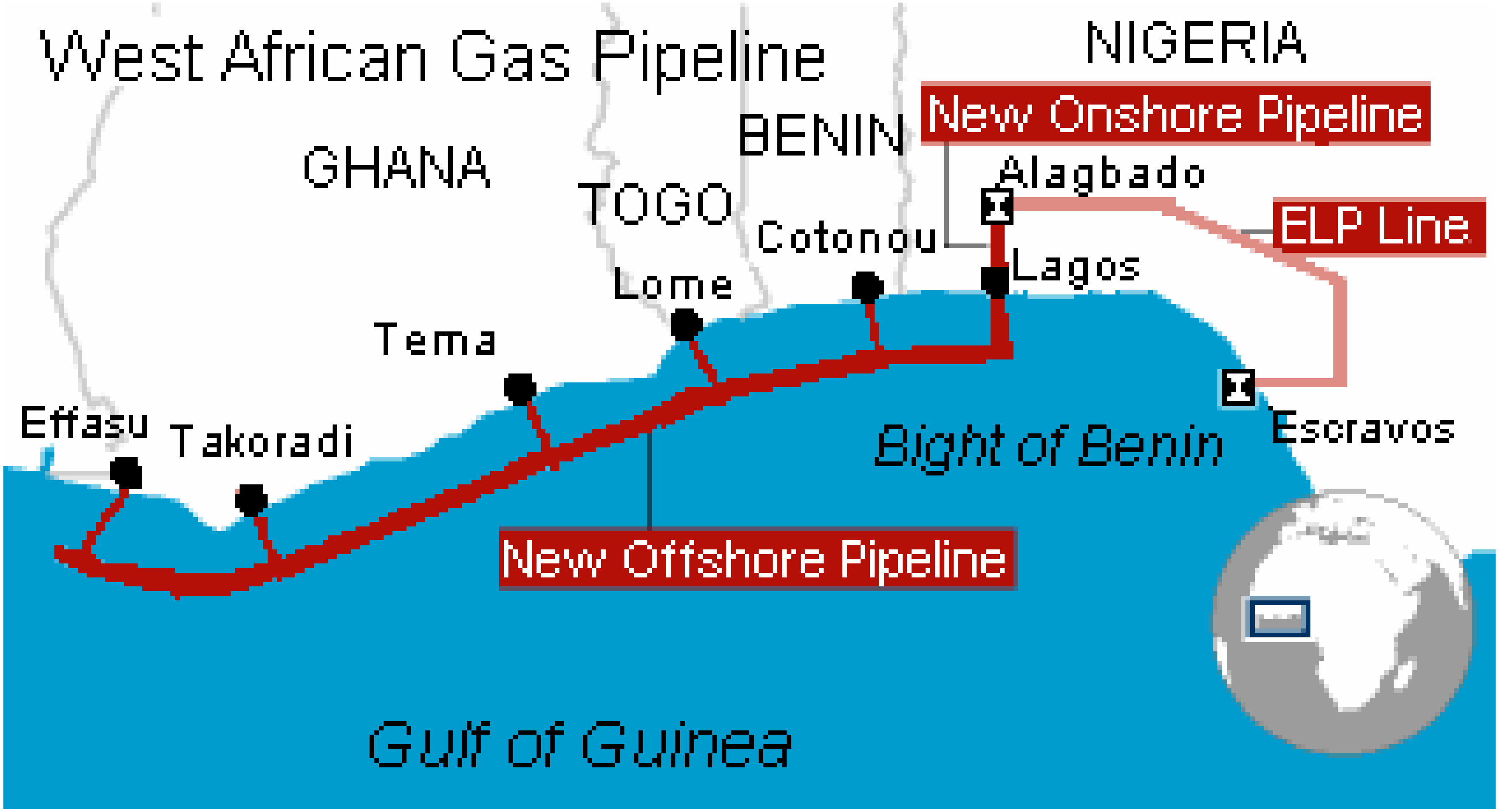
Case study – City of Erzurum

- Five qualified bidders
- Eventual winner's first bid was 0.0078 cent/kWh, or 0.242 $/MMBtu
- After further discounting, 0.0046 cent/kWh, or 0.137 $/MMBtu
- $180 fee per connection
- ~$700 per certificate to equipment installers; ~$70 renewal fee per year; ~$10 installation inspection and approval

Case study – City of Erzurum

- Investment
  - $4.8 million in 2004 for 122 km of pipe + other facilities
  - 2005-33: $11.2 million for 261 km of pipe + other facilities
- 40,000 residential customers by 2005, consuming ~80 MMcm/year
- 42 MMcm/year C&I load
- 6.4 bcm cumulative 2004-2033

Case Study: Ghana



Source: http://www.eia.doe.gov/emeu/cabs/wagp.html

Natural gas market in Ghana

- The main market for the WAGP gas
- The 550-MW Takoradi Thermal Power Plant is being upgraded to 660 MW
- The plant will use ~100 million standard cubic feet a day (mmscfd) of natural gas to generate ~5 terawatthours (TWh) of electricity annually

Other potential users

- Large industrial users in Tema and Takoradi
  - Estimated demand of 4-20 MMscfd from existing facilities
  - Expected annual demand growth rate of 5%
- Mining industry north of Takoradi
- More power generation
- Commercial users, including transportation
- Residential sector NOT an immediate option

Backup power

	2008	*2012*	*2015*	*2020*
National diesel demand in 1000 tonnes	**1,100-1,300**	**1,500-1,600**	**1,800-2,000**	**2,300-2,500**
Diesel demand by industries for back up power in 1000 tonnes	**99-117**	**135-144**	**162-180**	**207-225**
Natural gas requirement in MMscfd	**10-12**	**13-14**	**16-18**	**20-23**

Source: Strategic National Energy Plan 2006-2020, Energy Commission, Ghana, 2006

RFO demand

Year	Economic growth scenarios	Fuel oil (without access to natural gas)	Fuel oil (with access to natural gas)	Implied Natural gas use
		Thousand tonnes		MMscfd
2008	Above 7% per annum	197–198	66-70	13 - 14
	5–7 % per annum	124–125	41-42	8 - 9
2012	Above 7% per annum	214–217	71-75	14 – 15
	5–7 % per annum	134 – 136	44-45	9
2015	Above 7% per annum	236-237	78-90	15 - 18
	5–7 % per annum	146-147	48-50	9 - 10
2020	Above 7% per annum	255–260	95-115	18 - 23
	5–7 % per annum	156–159	52-54	10 - 11

Source: Strategic National Energy Plan 2006 – 2020, Energy Commission, Ghana, 2006

Distribution systems

- Relatively small number of users in both Tema and Takoradi → small systems
- In Tema,
  - Backbone: a 7-8 km 8 to 12-inch steel line
  - Laterals: <15 km of 4 or 6-inch HDPE lines
- In Takoradi,
  - Backbone: a 5-6 km 8 to 12-inch steel line
  - Laterals: <15 km of 4 or 6-inch HDPE lines

Economics of these systems

- Very small systems that can be built in a month or two at about $3 million each
- A distribution tariff of ~$0.20/MMBtu will yield a return of 15% to LDC
- Relative to total cost of gas, distribution tariff is a small increment

Initial cost of gas to end users

- Known factors
  - Oil Indexation of $0.20-1.00 ($30-60/bbl)
  - Cost of gas in Nigeria of ~$0.55/MMBtu
  - Gas sales handling fee of ~$0.10/MMBtu
  - ELPS tariff of ~$0.25/MMBtu
- WAGP cost
  - $1.90/MMBtu (100 to 470 MMscfd from 2007 to 2026)
  - as high as $5.00/MMBtu if demand remains low
- Distribution tariff of ~$0.20/MMBtu
- Conversion cost of ~$0.05/MMBtu
- **TOTAL COST of $3.25-7.15/MMBtu**

Comparison with other fuels

Crude oil		LPG	RFO	Diesel	Natural gas
US$ per barrel	Average US$/MMBtu				
60	10.30	15.40	8.25	14.40	4.05–7.15
45	7.75	12.30	6.60	11.00	3.70–6.75
30	5.51	8.80	4.60	7.70	3.30-6.30

As long as the price of oil > $30/barrel, natural gas can be competitive if demand is high enough.

Cost of power

- New combined cycle generation will produce electricity at 4.5 to 7.5 cents per kWh for $3.25 to $7.15 per MMBtu gas
- Retrofitted Takoradi plant should produce 1-1.5 cents per kWh cheaper
- Industrial cogeneration can be even more beneficial especially if sale of excess power to the grid is allowed

CNG for transportation

- $1 million for a 500 m^3 compression station
- $700-$1,000 to convert a car, recoverable
  - in <12 years for **$3.10** gas and **$30** oil
  - in <4 years for **$3.10** gas and **$50** oil
  - in <8 years for **$6.15** gas and **$50** oil
- Requires a widespread pipeline network
  - Many stations, easy access
  - Otherwise, viable only for fleets

Concluding remarks

- Natural gas offers a competitive and cleaner alternative for many uses
- No incentives are needed to switch unless oil price collapses below $30/bbl
- Secondary pipeline infrastructure should be initiated in Tema and possibly Takoradi
  - to connect industrial users
  - to allow new power generation, including cogeneration
- Beyond foundation volumes, new gas purchase agreements need to be signed

Case Study: Peru

- Camisea field: 13+ tcf of gas reserves
- Export opportunities limited
- Primary domestic market: power generation
- Secondary market: commercial & industrial customers in Lima and surrounding areas
- Tertiary market: residential and transportation users in Lima and surrounding areas

New LDC

- 33 year renewable concession to Calidda, a subsidiary of Suez Energy International
- Started on December 13, 2004
- Jan 18, 2005: first industrial customer
- Mar 14, 2005: first residential customer
- Oct 25, 2005: first filling station for NGVs
- By end of 2006: 150+ industrial, 3,000+ commercial, 10,000 residential customers, 8 filling stations, 900+ NGVs, 17+ conversion shops

Policies & regulations

- Guaranteed "real annual profitability of 12%" for T&D concessions
  - T: $38 per 1,000 cm ($1.08 per MMBtu)
  - D: $8 per 1,000 cm ($0.23 per MMBtu)
- $1/MMBtu for power generation
- $1.9/MMBtu at Lima city gate
- New power generation facilities to serve large mining companies, utilities, and cement manufacturers.

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LNG Value Chain

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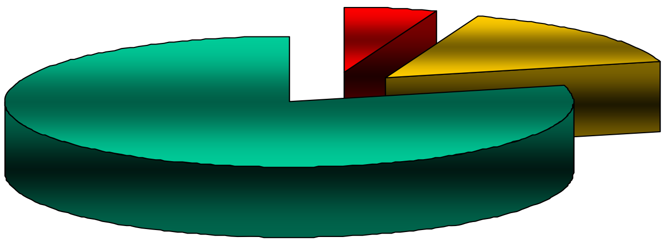
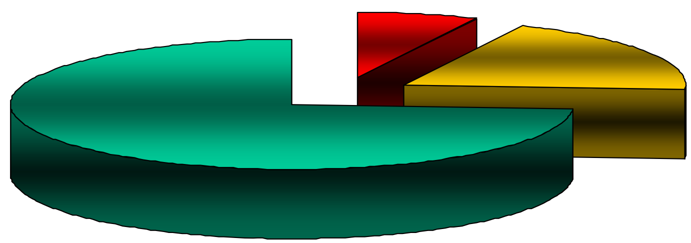
World Natural Gas Supply (Trade)

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



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



Sources: BP Annual Statistical Review, 2006

Liquefaction

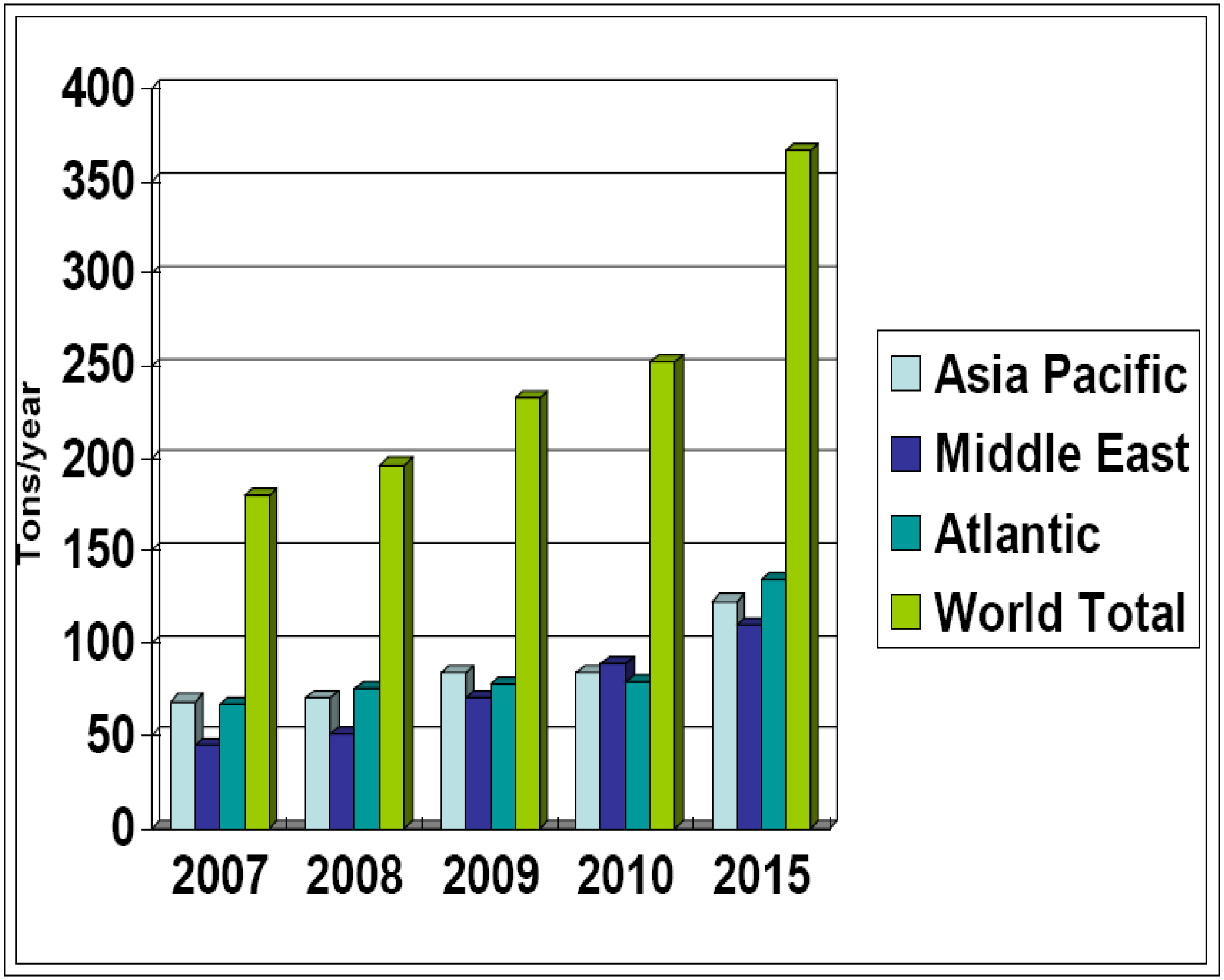
Global Liquefaction Plant Capacity (mtpa) as of March, 2007

Region	Operating	Under Construction	Planned	Total
Pacific Basin	68.9	23	77	168.9
Middle East	36.3	56.7	43.8	136.8
Atlantic Basin	65.5	11.6	164.1	241.2
TOTAL	**170.7**	**91.3**	**284.9**	**546.9**

Actual production 2006: 168 mt

Sources: Various industry sources and trade publications

Projected Liquefaction



Source: Poten & Partners / Hess LNG

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

Ship Capacity (m^3)	Ships in Operation	Ships on Order	Total
18,000 to 50,000	20	1	21
51,000 to 120,000	15	2	17
>120,000	189	97	286
209,000 to 270,000	-	45	45
Total	**224**	**145**	**369**

Sources: Various industry sources and trade publications

Global Regasification Terminals by Regions (as of March 2007)

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

**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

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LNG Value Chain Costs




EXPLORATION & PRODUCTION	LIQUEFACTION	SHIPPING	REGASIFICATION & STORAGE
$0.5-$1.0/MMBtu	$0.8-$1.20/MMBtu	$0.4-$1.0/MMBtu	$0.3-$0.5/MMBtu

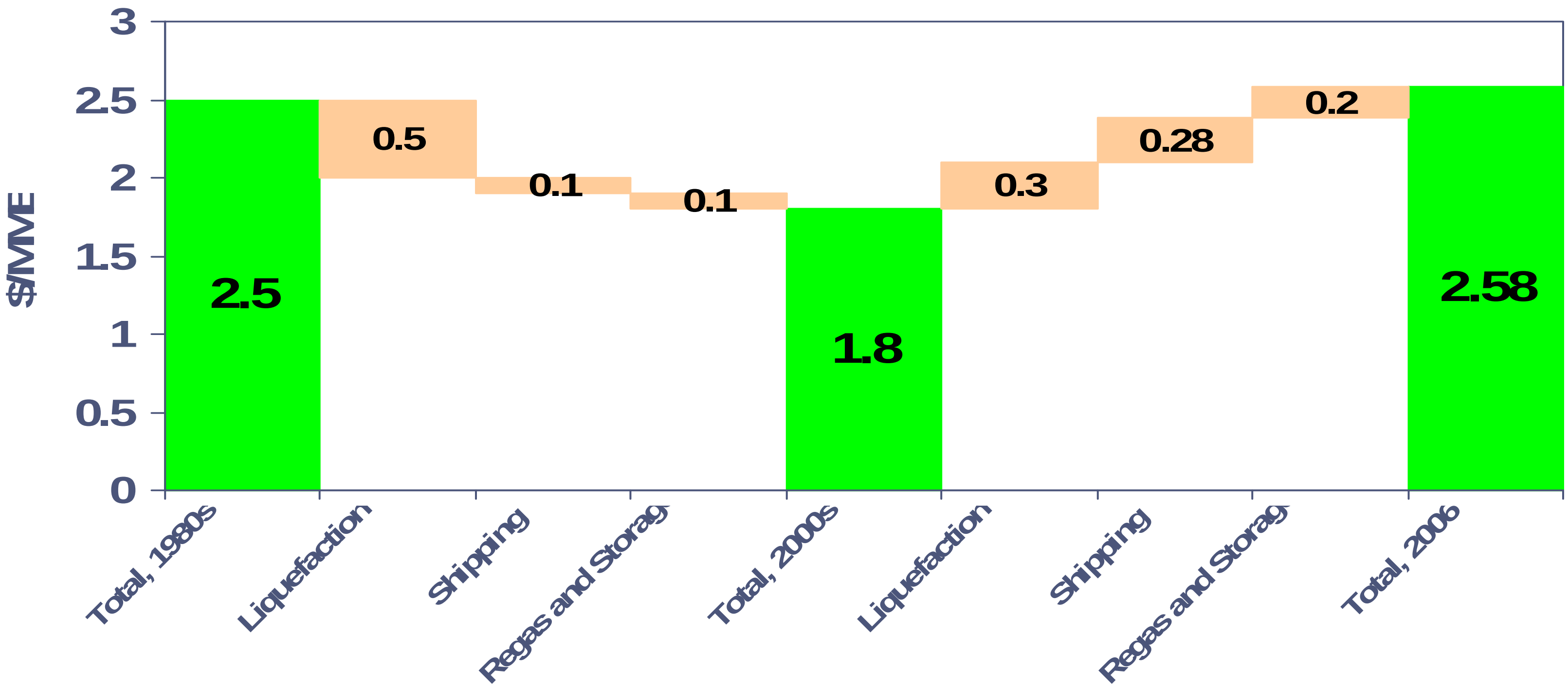
TOTAL = $2.00 - $3.70

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?



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

New LNG Contract Trend

	Old	New
Example Project	Australia - N.W. Shelf 1989	Trinidad - Atlantic LNG 1999
Sold To	Japan	US
Built with	High CAPEX	Low CAPEX
Sold through	Oil-indexed pricing	Gas-Gas competition
Sold with	Rigid Terms	Flexible Terms
Yielding	Low risk/Low return	High risk/High return

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 co-operation 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

Source: **Guy Ranawake, Taylor DeJongh, *Market Price Risk – The New Realities and LNG Project Finance Structure,* Bahrain, 2004**

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

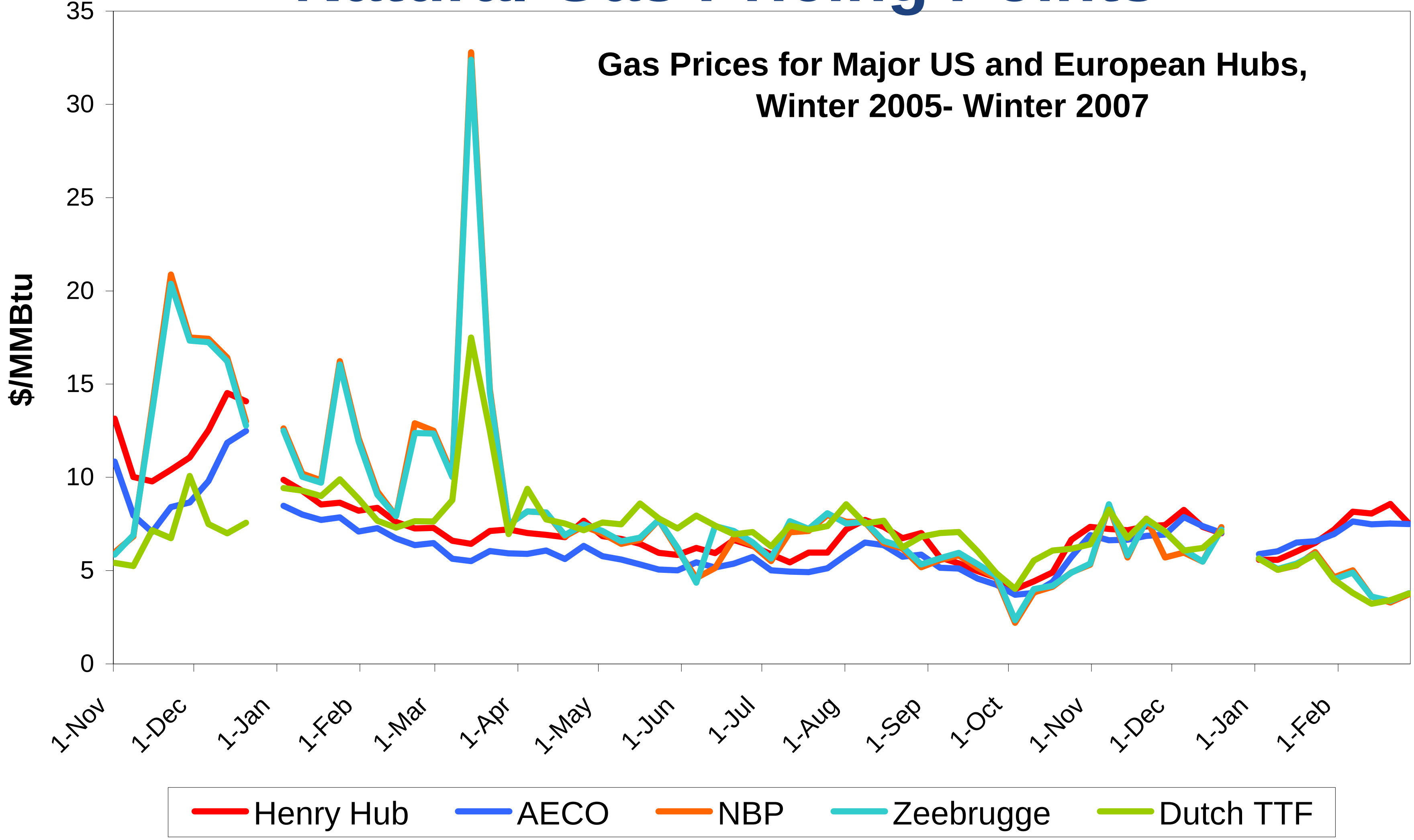
***Source*: Guy Ranawake, Taylor DeJongh, *Market Price Risk – The New Realities and LNG Project Finance Structure,* Bahrain, 2004**

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.

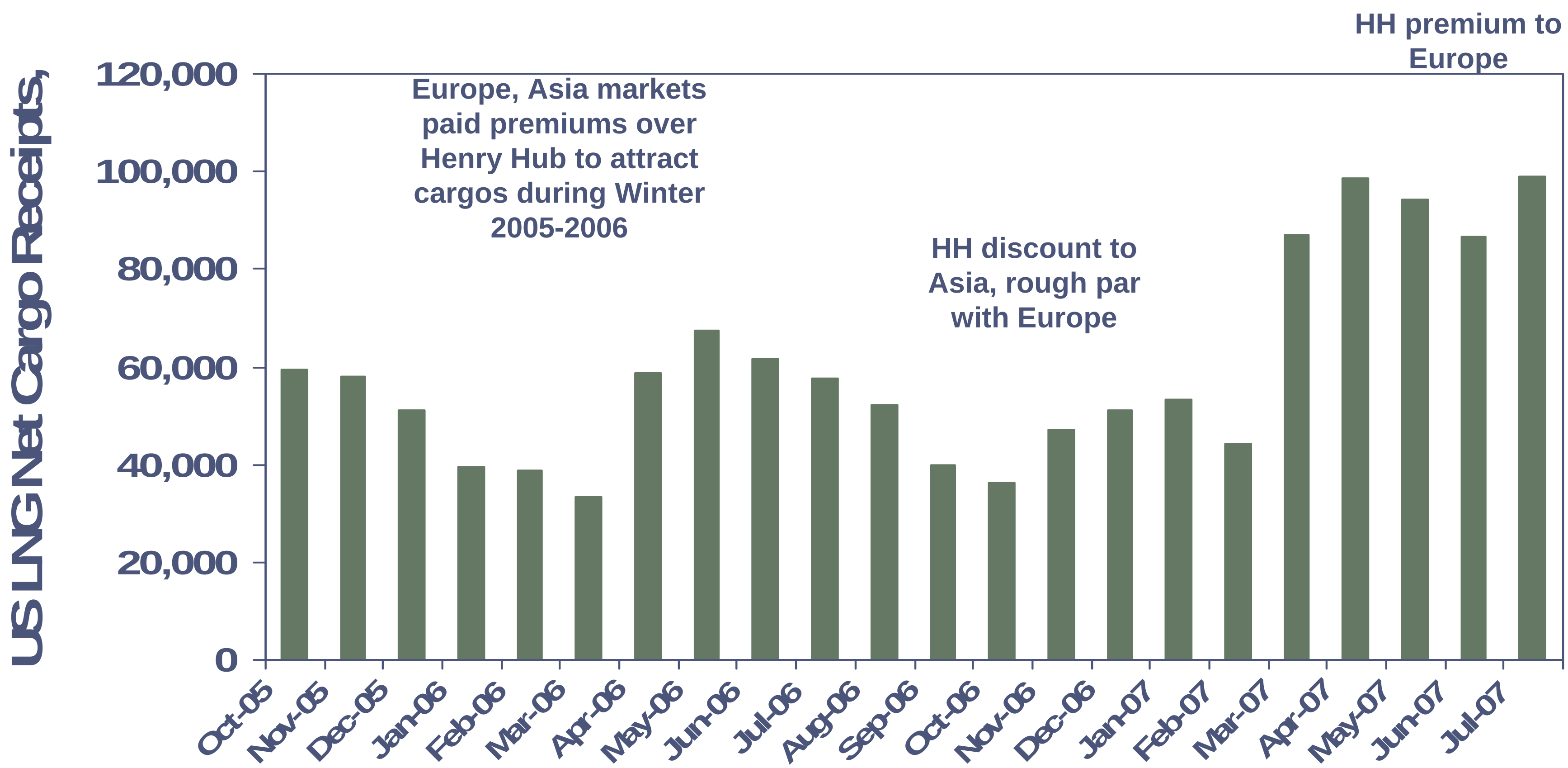
***Source: IEA (2002), "Flexibility in Natural Gas Supply and Demand", TEPCO (2002), "Press Release*; Guy Ranawake, Taylor DeJongh, *Market Price Risk – The New Realities and LNG Project Finance Structure,* Bahrain, 2004**

Natural Gas Pricing Points



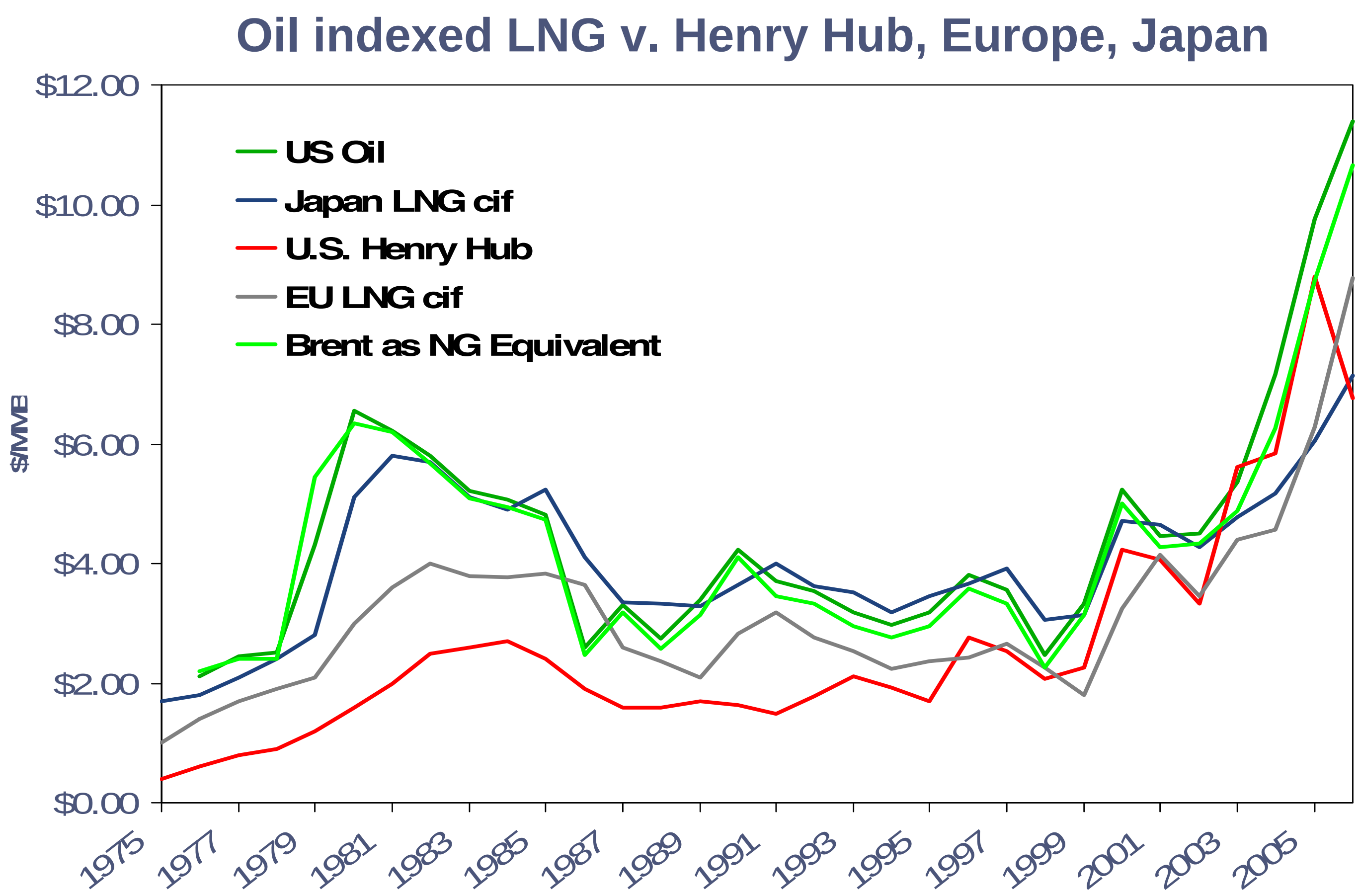
Sources: World Gas Intelligence

LNG Commercial Efficiencies



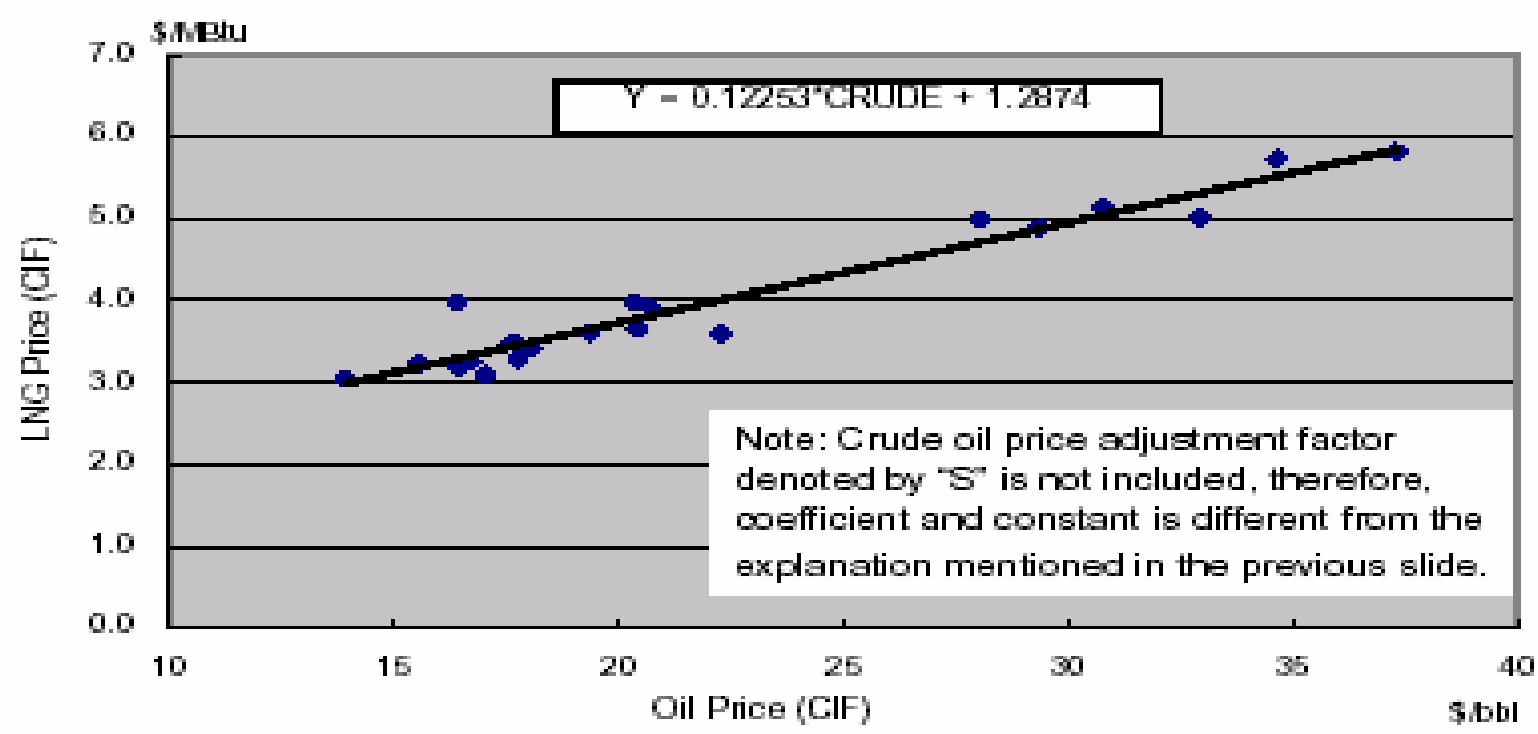
Sources: U.S. EIA

Price Convergence?



Sources: BP, GasMatters, NYMEX

Correlation between LNG Price and Crude Oil Price



Sources: 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 * 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 * 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= (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-JCC)/($16.5-$11.0)
- Source: Middle East Economic Survey (2001)

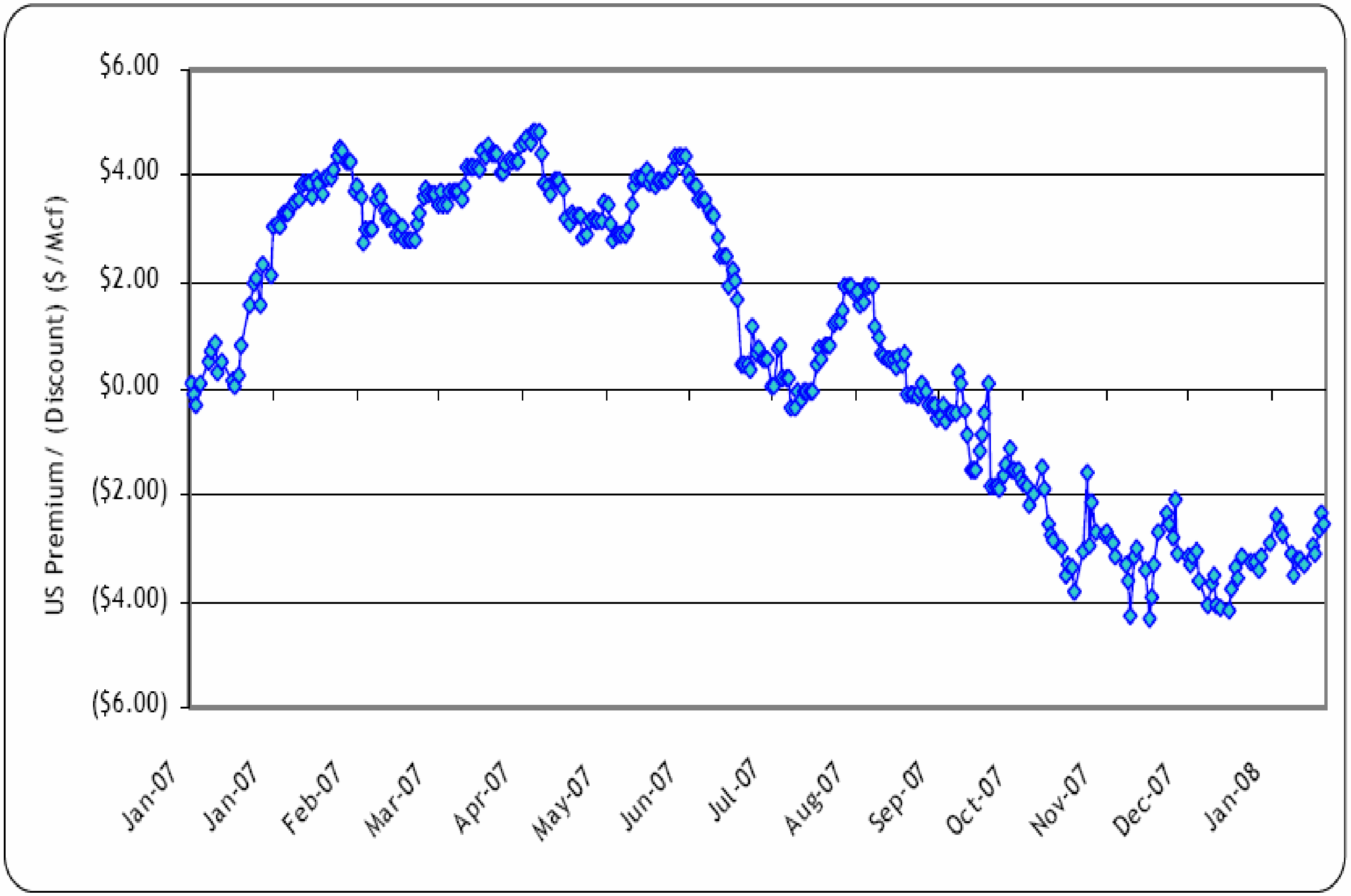
Presented in Jung,Yonghun Ph.D, Asia Pacific Energy Research Centre, Tokyo, *An Outlook for Natural Gas Market in the APEC Region*, Tokyo, 2003

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.

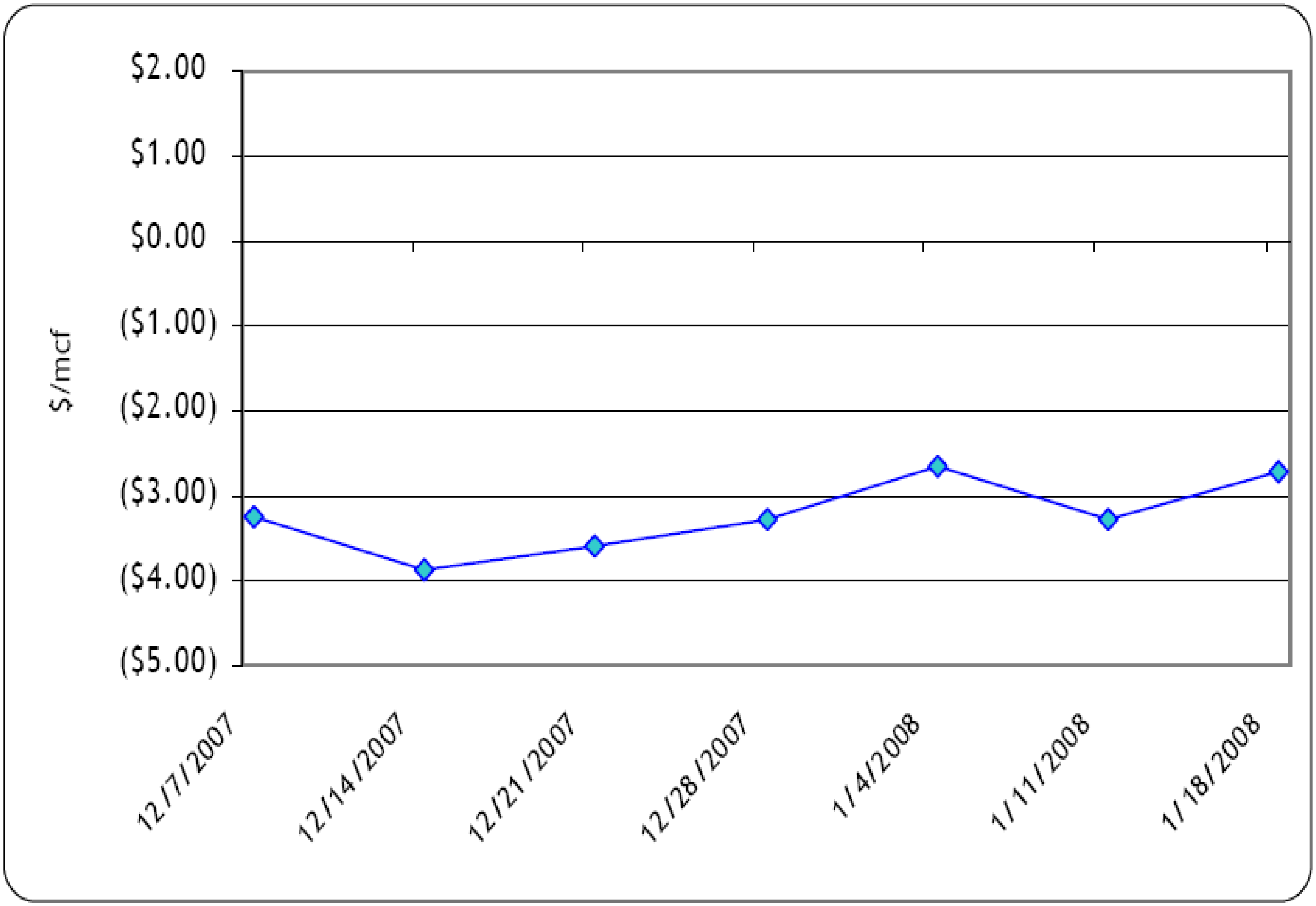
Jung,Yonghun Ph.D, Asia Pacific Energy Research Centre, Tokyo, *An Outlook for Natural Gas Market in the APEC Region*, Tokyo, 2003

US/UK Prompt Month Gas Price Arb

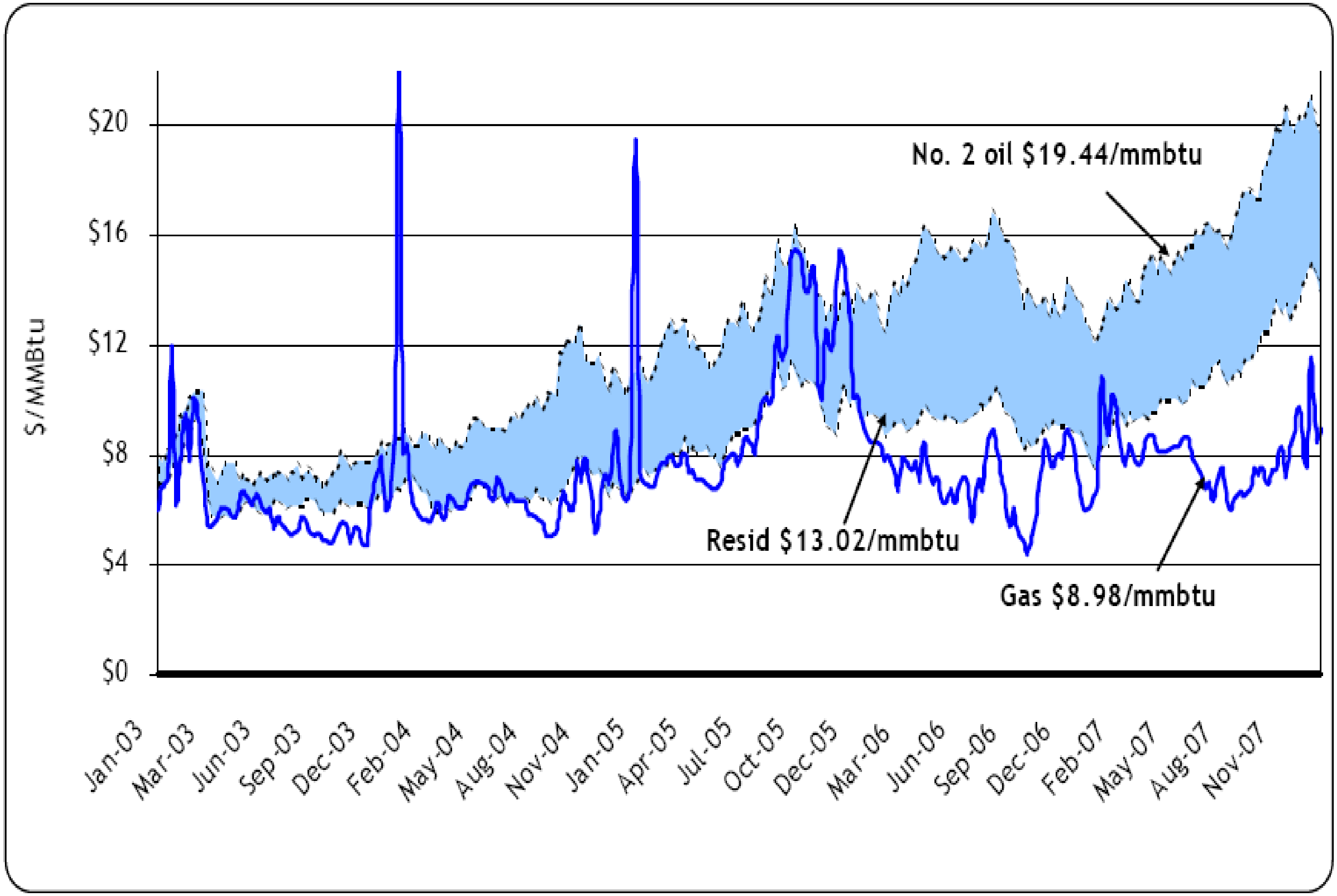


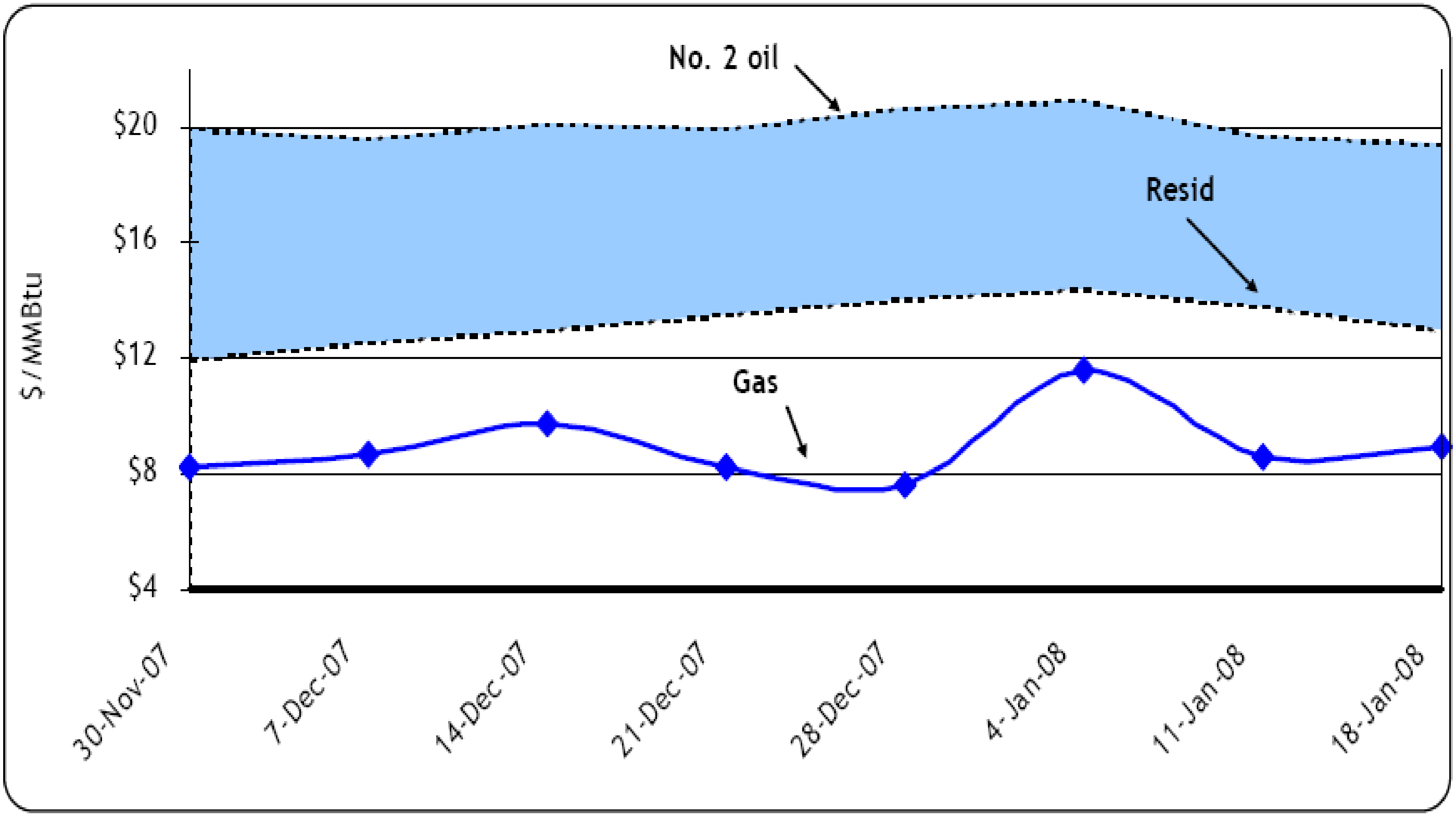
Source: Bloomberg, Tudor, Pickering & Holt

US/UK Prompt Trailing 7-week Price Arb



Fuel Switching - priced at New York City Gate ($/mcf)

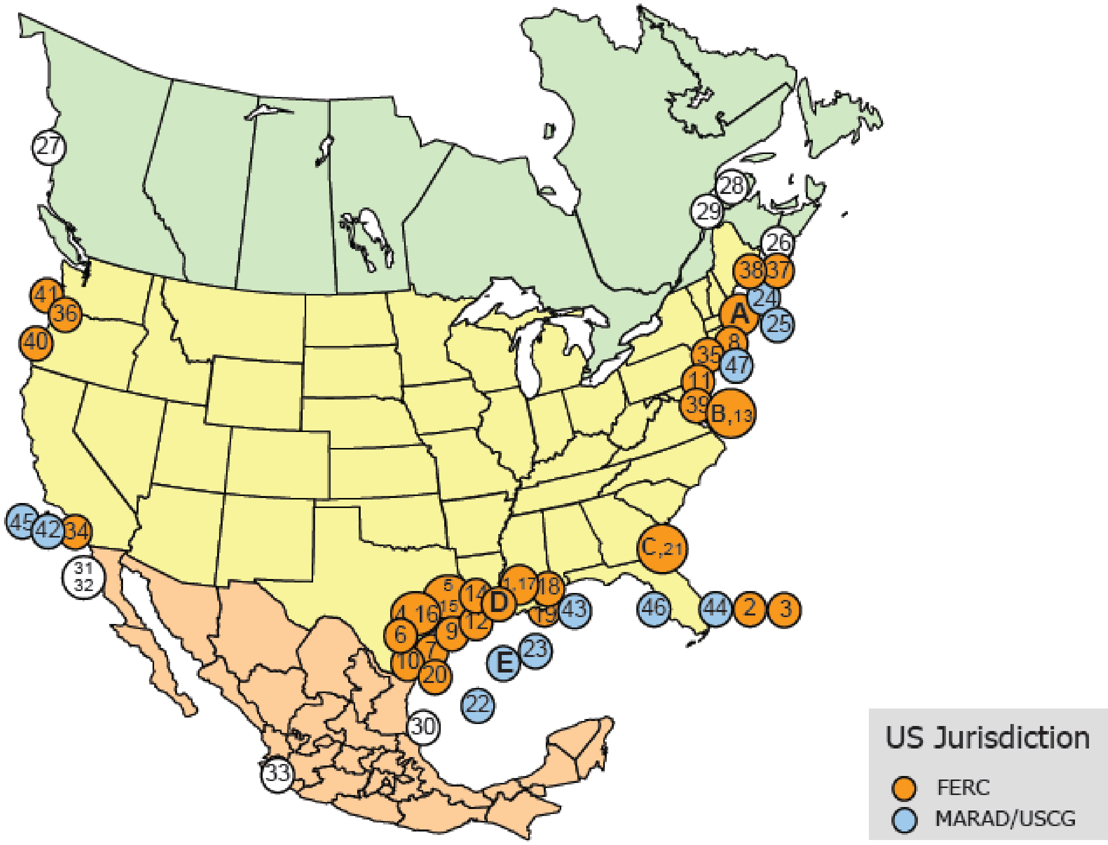




Source: Bloomberg

FERC

Existing and Proposed North American LNG Terminals

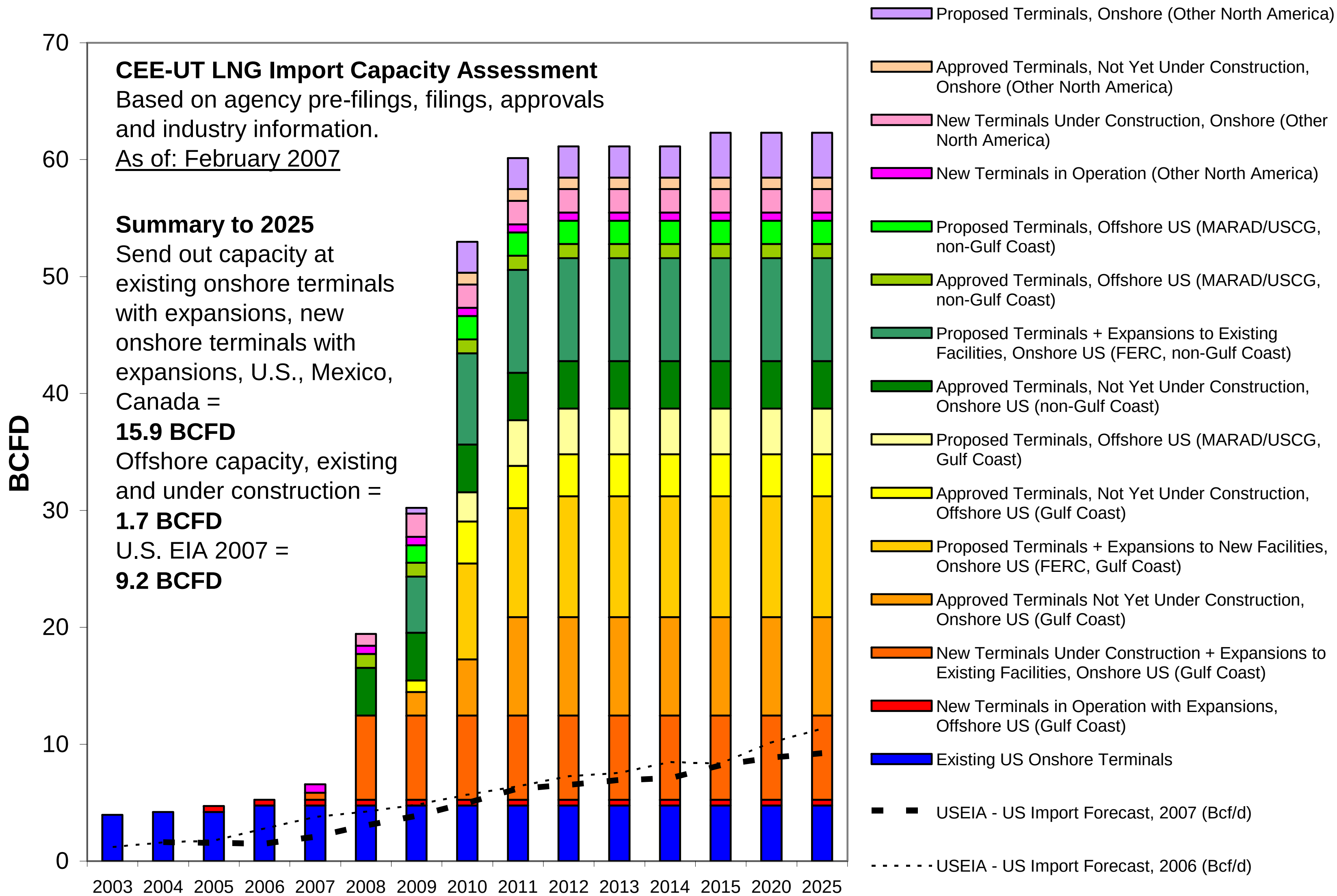


As of January 14, 2008
Visit our LNG Section at
www.ferc.gov/industries/lng.asp

* *US pipeline approved; LNG terminal pending in Bahamas*
** *Construction suspended*

Office of Energy Projects

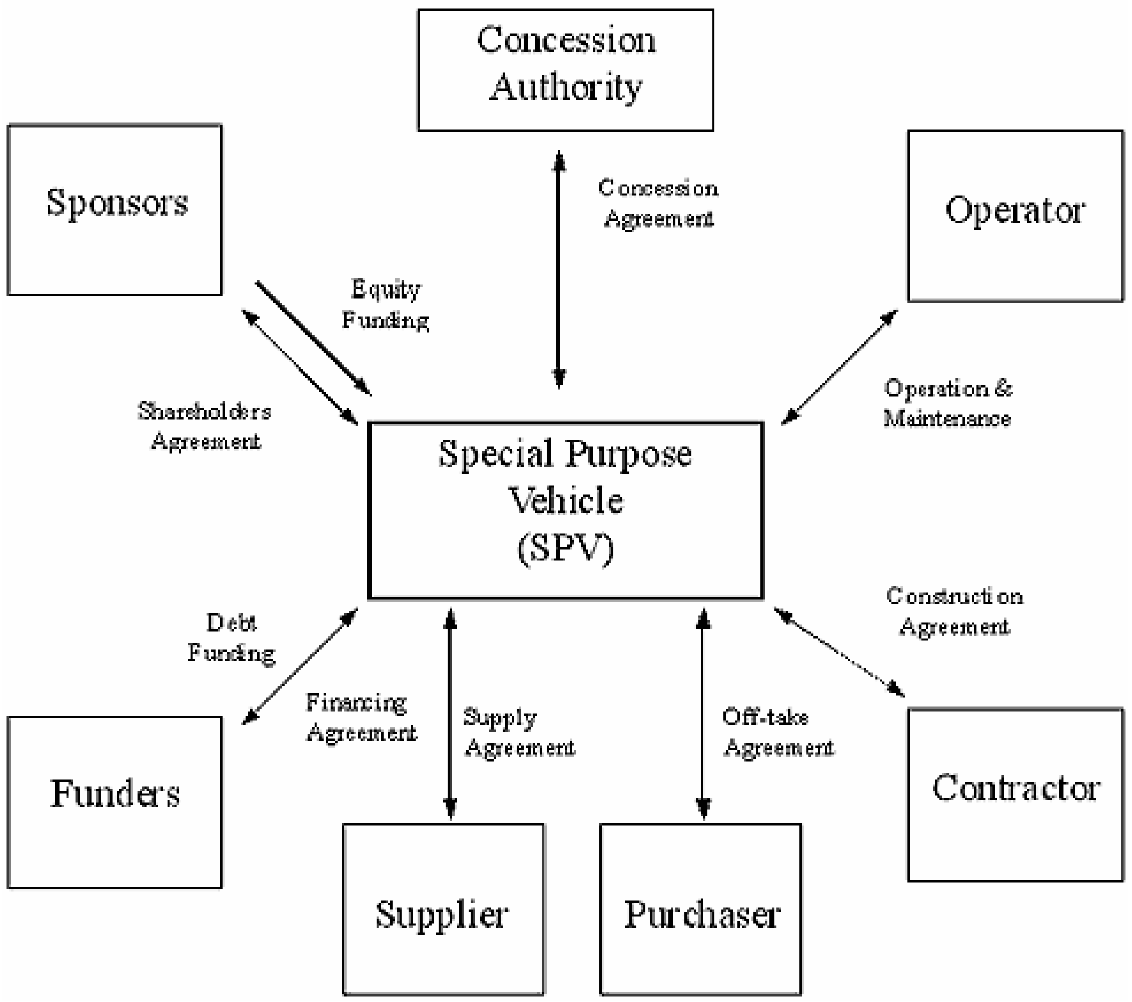
US Regasification Infrastructure



SARI / Energy

Project Finance: LNG Example

Diagram of Project Finance and Special Purpose Vehicle

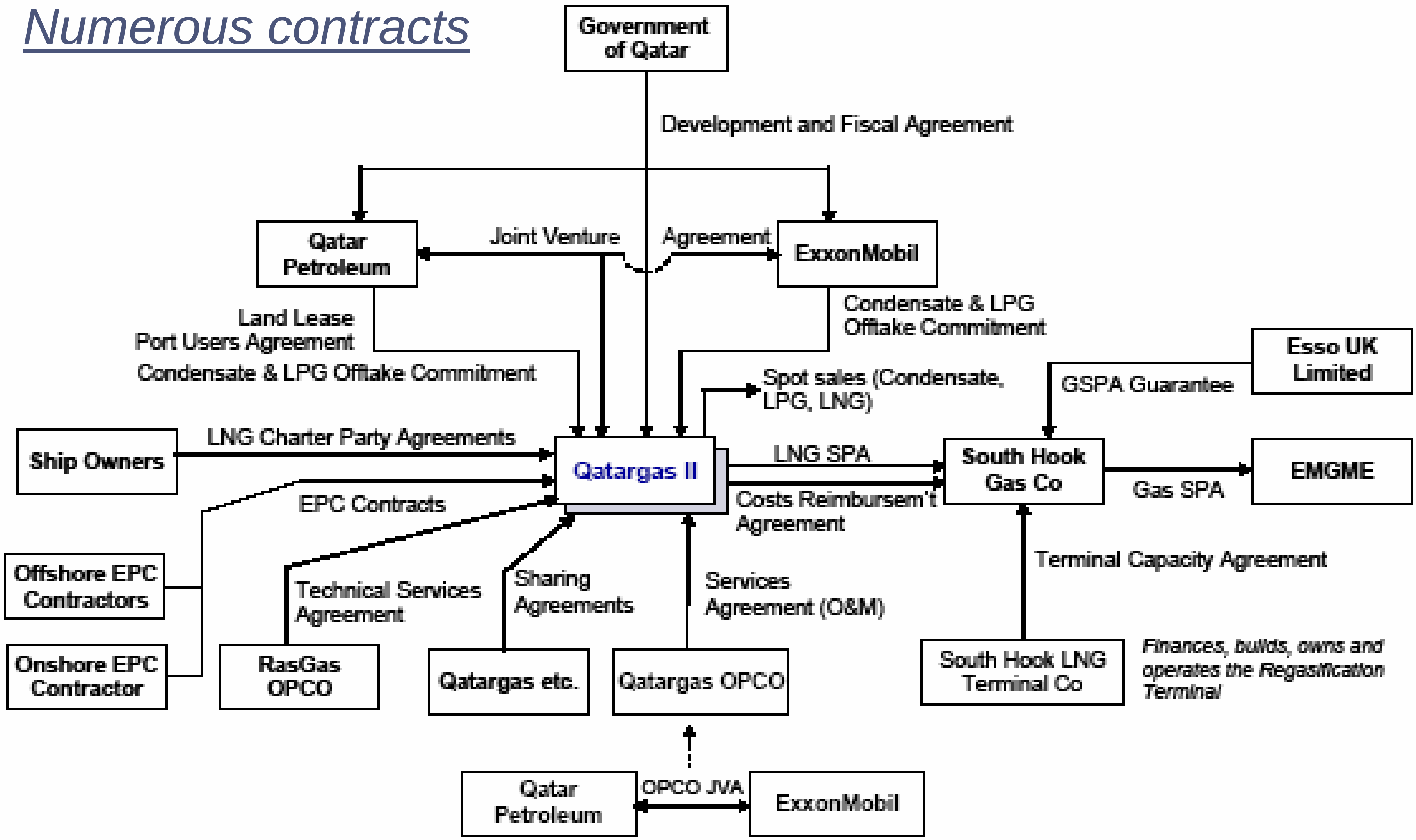


Qatargas II LNG Project

- Joint Venture between Qatar Petroleum (70%) and ExxonMobil (30%)
- World-scale and multi-product
- $9.3 billion two-train financing with Train I targeting the UK gas market
  – Debt: $6.5 billion; Equity: $2.8 billion
- Output (Two-Trains):
  – 15.6 MTPA of LNG (approx. 12% of current global production)
  – 6 MMTA of Condensates
  – 1.7 MMTA of LPG

Qatargas II LNG Project (contd.)

Numerous contracts



Qatargas II LNG Project (contd.)

- Due to integrated nature of the project, credit analysis needs to consider entire LNG supply chain
  - Upstream development and liquefaction: QP & ExxonMobil are sponsors (project also relies on certain shared facilities)
  - Shipping: Charter Agreements (8 Large LNG vessels per train, financed separately)
  - Regasification Terminal (South Hook, Wales, UK): QP (70%), ExxonMobil (30%) with £600 million in debt financing (including £180 million in ExxonMobil sponsor loan)
  - Gas Offtaker: ExxonMobil Gas Marketing Europe (EMGME)
    - Volume commitment; price risk to Project
  - Condensate & LPG marketing
    - Volume commitment; price risk to Project

Qatargas II: Debt Financing

- Highly Successful: Despite complexity and size of the project, financing was arranged in one year and resulted in attractive pricing and generous tenors
- Commercial Bank Facility
  - $3.6 billion, 15 years
  - Pricing: 50 bp (yrs 1-5) rising to 125 bp (yrs 13-15)
- Islamic Facility
  - $530 million, 15 years
  - Structured to mimic Bank Facility
- ECA-Guaranteed Facilities
  - $805 million, 16.5 yrs (SACE: $400 million at 21bp, US Ex-Im: $405 million at 2 bp)
- ExxonMobil Sponsor Loan
  - $1.9 billion (as mirror facilities)

Qatargas II LNG Project (contd.)

- Cashflow Waterfall
  - Project Revenue net of regasification, UK system entry, and marketing costs
    - Less: Qatari Royalties
    - Less: Shipping Costs and Upstream/Liquefaction O&M Expenses
    - Less: Qatari Corporate Income Taxes
    - Plus: Deferral of Bank/Islamic Debt Service (if any)
  - Cash Flow Available for Senior Debt Service
    - Less: Senior Debt Service
    - Less: Funding of Debt Service Reserve Account
  - Cashflow available for Equity (transferred to Offshore Borrower Distribution Account) can be released to Sponsors if certain criteria are met (e.g., DSCR needs to be higher than an agreed upon level)

Qatargas II: Allocation of Key Risks

- UK gas price risk borne by project and, therefore, its lenders
- Volume risk passed through to EMGME via a 25-year offtake agreement backed by ExxonMobil credit support
- Development and construction risks associated with the liquefaction plant and new downstream infrastructure (ships and regasification terminal) transferred to project sponsors through a financial completion test
  - Provisions of the completion test include liquefaction, shipping and regasification (at the South Hook terminal) of a defined LNG cargo
- Project has option to borrow under defined scenarios and parameters (e.g., for expansion purposes)