LNG COMES OF AGE IN NORTH AMERICA

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JAMES T. JENSEN
Jensen Associates
49 Crescent Street; Weston, MA 02493 U.S.A.

Phone (781) 894 2362
Fax (781) 894 9130
E Mail JAI-Energy@Worldnet.ATT.Net

Website JAI-Energy.com

THE "GAS PRICE SHOCK" OF THE WINTER OF 2000/01 HAD TWO IMPORTANT CONSEQUENCES

- It Raised Questions About the Ability of the North American Gas Industry to Support a High Growth Rate in Demand Without Putting Significant Upward Pressure on Prices

- And it Revived Interest in Higher-Cost Alternative Supplies, Such as LNG and Arctic Gas

FOR LNG, THE NORTH AMERICAN GAS SUPPLY CRUNCH IS THE ICING ON A CAKE THAT HAD ALREADY BENEFITTED FROM

- The Emergence of Gas as the Fuel of Choice for Power Generation Because of the Attractive Economics of Gas-Fired Combined Cycle Techology

- A Substantial Reduction in LNG Costs That Has Made Previously Uneconomic Trades Appear Attractive

- And The Oil Companies' Growing Interest in Monetizing "Stranded Gas Assets"

THE 1999 STARTUPS OF THE NIGERIA AND TRINIDAD LNG PROJECTS - THE FIRST SIGNIFICANT EXPANSION OF ATLANTIC BASIN LNG CAPACITY IN NEARLY TWENTY YEARS - USHERED IN THIS NEW ERA IN LNG

- Nigeria Provides an Illustration of the Evolution of Today's Optimism About the Economics of LNG Supply to the U.S.

- In the Mid-1990s, a Consortium of Shell, AGIP, Elf and NNPC, Started Negotiations on What Has Become the Bonny LNG Project

- Initially the Sponsors Could Not Demonstrate Economic Feasibility for a Project Destined for Italian and U.S. Markets

- But by Taking Very Low-Cost Options on Seven Laid-Up LNG Tankers at a Time When the Price of Newbuilds

- The Following Figure Illustrates the Economics that a New Nigerian Greenfield Project Destined for the U.S. Gulf Coast Might Have Faced in 1998, Given the Designs, Costs and Price Expectations of the Period.

- As is Evident, the Project was a Non-Starter Since the Initial Netback to the Inlet of the Liquefaction Plant was Negative (-$0.21)

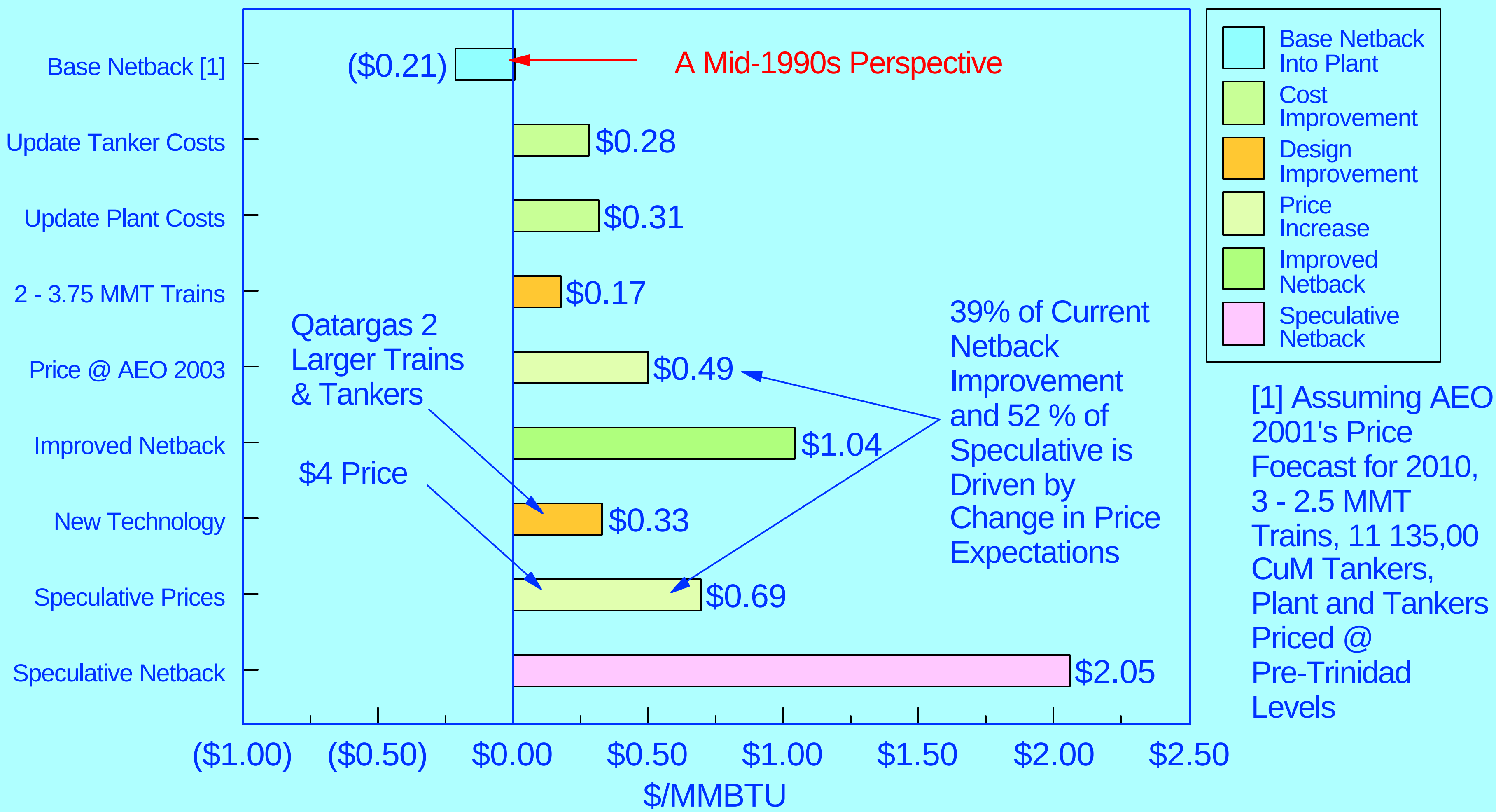
- Figure 1 Then Traces the Improvements in Netbacks As a Result of Using Current Cost Estimates for the Original Design, as Well as the Design Improvements in Plant Economics from Increasing Plant Sizes - Two 3.75 MM Ton Trains, Instead of Three 2.5 MM Ton Trains

- But an Even Larger Contribution to the Improvement Comes From the Newer Gas Price Expectations
- If One Accepts the Growing View That Supply/Demand Balances Will be Tight and Prices Will Remain High, LNG Economics Look Much Better
- A Substitution of the EIA'S Annual Energy Outlook 2003 Price Forecast for One Made Only Two Years' Earlier Accounts for Nearly 40% of the total $1.25 Netback Increase from These Demonstrated Improvements in the Pricing Expectations
- If One Were to Adopt the More Speculative Technology that Qatargas 2 is Considering - 7.5 MM Ton Trains and 250,000 Cubic Meter Tankers - Together with an Optimistic $4 Gas Price, the Netback Would Increase Even Further

Figure 1

THE EVOLUTION OF OPTIMISM ABOUT LNG IMPORTS

THE CHANGING PERSPECTIVE OF U.S. NETBACKS FROM THE U.S. GULF TO A NIGERIAN GREENFIELD PLANT FROM 1998 TO 2003



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BUT DESPITE THE JUSTIFIED OPTIMISM ABOUT THE PROSPECTS FOR NORTH AMERICAN LNG, THE SUDDEN EMERGENCE OF LNG AS THE LATEST "FASHIONABLE" ENERGY SOURCE HAS BRED A MYTHOLOGY OF ITS OWN ABOUT ITS ROLE IN NORTH AMERICAN GAS SUPPLY

- Two Current LNG "Myths"

    o The Availability of LNG Imports Will Put a "Cap" on U.S. Gas Prices

    o That If We Solve the Terminal Siting Problem, LNG Will Play the Same Role in Supplementing Domestic Gas Supply That Imported Oil Now Does for Domestic Oil Production

MYTH # 1 - THE AVAILABILITY OF LNG IMPORTS WILL "PUT A CAP" ON U.S. GAS PRICES

- This Myth is a Reincarnation of What Might be Described as "Area Pricing, Cost-of-Service" Logic
- In 1954, the U.S. Supreme Court, in its "Phillips' Decison" Extended Utility Ratemaking to Gas at the Wellhead, Thus Introducing the Failed U.S. Experience in Gas Price Controls
- The Federal Power Commission, Charged With Regulating the Industry, Quickly Found That Cost-Based ("Cost-of-Service") Regulation Applied to Individual Producers Was Completely Unworkable in the Regulation of Gas Prices

- While Individual Producers Experienced Very Different Costs, Their Product Was a Fungible (Interchangeable) Commodity in the Marketplace
- In Addition, the Question of Joint Costing Reared its Head
- Were Wildcatters Looking for Hydrocarbons, in Which Case Exploration Costs Had to be Allocated Between Gas and Oil? Or Were They Actually Able to Direct Their Exploration, in Which Case All Exploration Costs Could be Assigned to Gas?
- Some Gas was Oilwell Gas While Other Gas Was Rich in Gas Liquids
- How Did One Allocate Costs Between Gas and Liquids?

- Finally, the FPC Hit Upon the Idea of Regulating Against Broad Area Cost Averages, Thus Coming Up With the Concept of "Area Pricing"

- The First Two Test Cases Were the South Louisiana Area Rate Case, Where NGLs Were Important, and the Permian Basin Area Rate Case, Which Featured Associated Gas; The FPC Thus Met the Joint Liquids/Gas Cost Allocation Problem Head On

- Congress's Final Acceptance of Deregulation Mercifully Ended The Struggle With "Cost-of-Service" Pricing and With it, the Attempt to Assign Costs to the Wellhead

- It Substituted Instead the Concept that Competition in the Marketplace Would Determine Prices for the Commodity and Individual Producers Could "Net Back" Prices to the Wellhead Regardless of their Individual Cost Structures

- Although North American Gas Prices are Now Determined by "Netbacks" From the Marketplace, "Cost-of-Sevice Pricing" Logic Has Been Subtly Revived by the Way in Which Gas Supply Models are Designed

- Most Models Construct Their Gas Supply Curves Using the Costs of Drilling and Developing Gas Reserves in Individual Producing Basins on the Assumption that Wellhead Competition Will Drive Prices to Cost-of-Service Levels; The Ambiguity of Joint Costing Between Gas and Liquids is No Longer Much of an Issue

- The Idea That the Same Logic Can be Applied to LNG is Encouraged by the Fact That the Margins Required for Liquefaction, Tanker Transport and Regasification Appear to Fit the Classic Cost-of-Service Model

- Thus, if One Assumes that LNG Comes From Just Another Competitive "Basin", it is Not a Major Leap to Assume that Cost-Based Pricing Applies to the Wellhead as Well: Or that Production Costs Will Ultimately Determine the Value at Which LNG Can be Imported into the U.S. to Set a "Cap" on U.S. Gas Prices

- Only That is Not the Way International LNG Pricing Works

- LNG Projects Have Always Been "Price Takers", Netting Back Prices to the Wellhead from a Reference Price That is Deemed to Represent the Market

- This is Especially Important Since Most LNG Projects are Based on Non-Associated Gas Fields that are Very Rich in Liquids (Ever Heard of "Negative Opportunity Cost Gas?)

- The Traditional Long Term Contract Typically Defined "Market Prices" in Terms of Other Fuels, Such as Oil; North American Industry Restructuring is Now Subsituting Gas-Linked Prices for the U.S.

- LNG Suppliers Operate on the Assumption that it is the U.S. Price Level That Will Determine Their Netbacks; Not That Their Costs Will Determine the U.S. Price Level

- Thus, the Effect of LNG on U.S. Prices is Likely to be the Same as That of Any Other Gas Supply; It Will be Reflected in the Overall Supply/Demand/Price Balance

- If Enough LNG Producers Find it Profitable to Compete for the U.S. Market , it Will Increase Supply and Weaken Prices; There is No Magic Cost-Based Price "Bench" at Which LNG Takes Over the Responsibility for Price Determination

MYTH # 2 - IF WE SOLVE THE TERMINAL SITING PROBLEM, LNG WILL PLAY THE SAME ROLE IN SUPPLEMENTING DOMESTIC GAS SUPPLY THAT IMPORTED OIL NOW DOES FOR DOMESTIC OIL PRODUCTION

- This Myth Was Born During the Winter of 2000/2001, When Shortages in the U.S Coincided With Surpluses in International Short Term LNG Markets
- It is Based on the Assumption That a Restructured International Gas Industry Will Always Maintain an Overhang of Competitively-Priced and Freely-Available Short Term Supply
- For a Time It Appeared that Very Large Scarcity Rents Could Be Made By Those With Terminal Capacity By Buying in the LNG Spot Market and Selling into the High-Priced U.S. Market - A "License to Print Money"

- However, When Prices Collapsed in Late Spring 2001, Prospective Terminal Economics Also Collapsed

- Figure 2 Compares the Estimated Pre-Tax Cash Flow as a Percent of Capital Investment for a New Independent Gulf Coast Terminal, My Estimated Hurdle Rate to Justify That Investment, and the Return Which the Investment Might Have Experienced in July/June 2000/01 and Again the Following Year

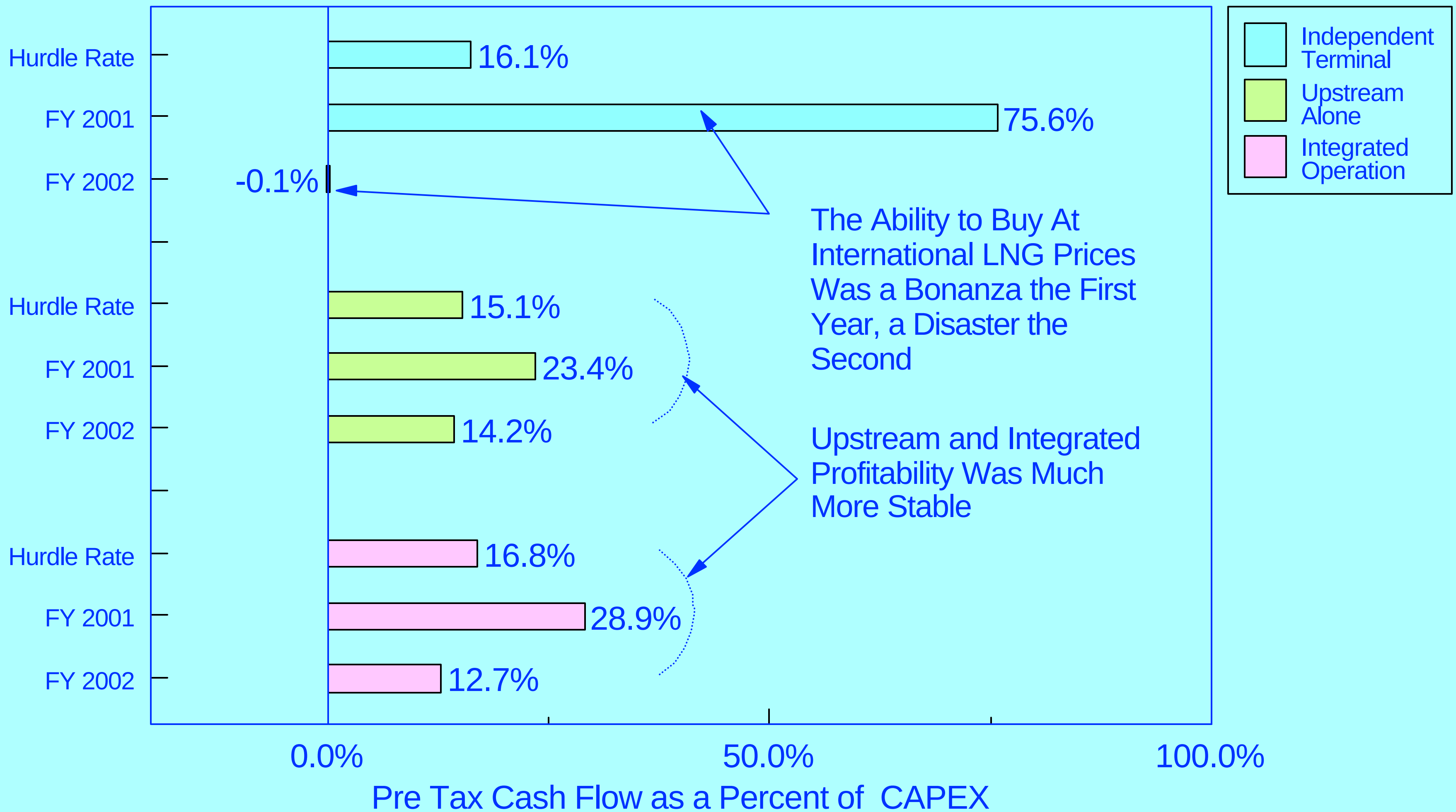
- The Netbacks are Based on the Experience at Lake Charles During the Period and Assume Operation at Design Capacity; On This Basis Everett Did Even Better

- The Profitability of Both an Upstream Operation Selling to the Independent Terminal and a Fully Integrated Operation Were Similarly Affected, Although Terminal Profitability Was Much More Volatile, Indicating the High Level of Risk in a "Naked" Terminal Investment

Figure 2

PRE TAX CASH FLOW AS A PERCENT OF CAPITAL INVESTMENT FOR AN INDEPENDENT GULF COAST MERCHANT TERMINAL

THE SHARP CHANGE IN PERCEIVED PROFITBILITY BETWEEN JULY/JUNE 2001/02 AND JULY/JUNE 2001/02



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- The Figure Presumes Terminal Operation at Design Levels; Actual U.S. Terminal Throughput Was Significantly Lower, Reflecting Competition With European Buyers for Cargoes (Figure 3)

- For Example, During the First Year, the Operating U.S. Terminals Experienced a Capacity Factor of 70%; During the Second Year, However, the Capacity Factor Dropped to 38%; It Has Now Recovered to 52%

- More Recently, a Shutdown of 15 Nuclear Plants by Tokyo Electric Has Upset World LNG Supply/Demand Balances and Tanker Availability Patterns to the Detriment of U.S. Markets

- Figures 4, 5, and 6 Illustrate the Competitive Netbacks to Trinidad, Nigeria and Qatar During These Three Periods

Figure 3

COMPARISON OF U.S. LNG TERMINAL IMPORTS WITH CAPACITY

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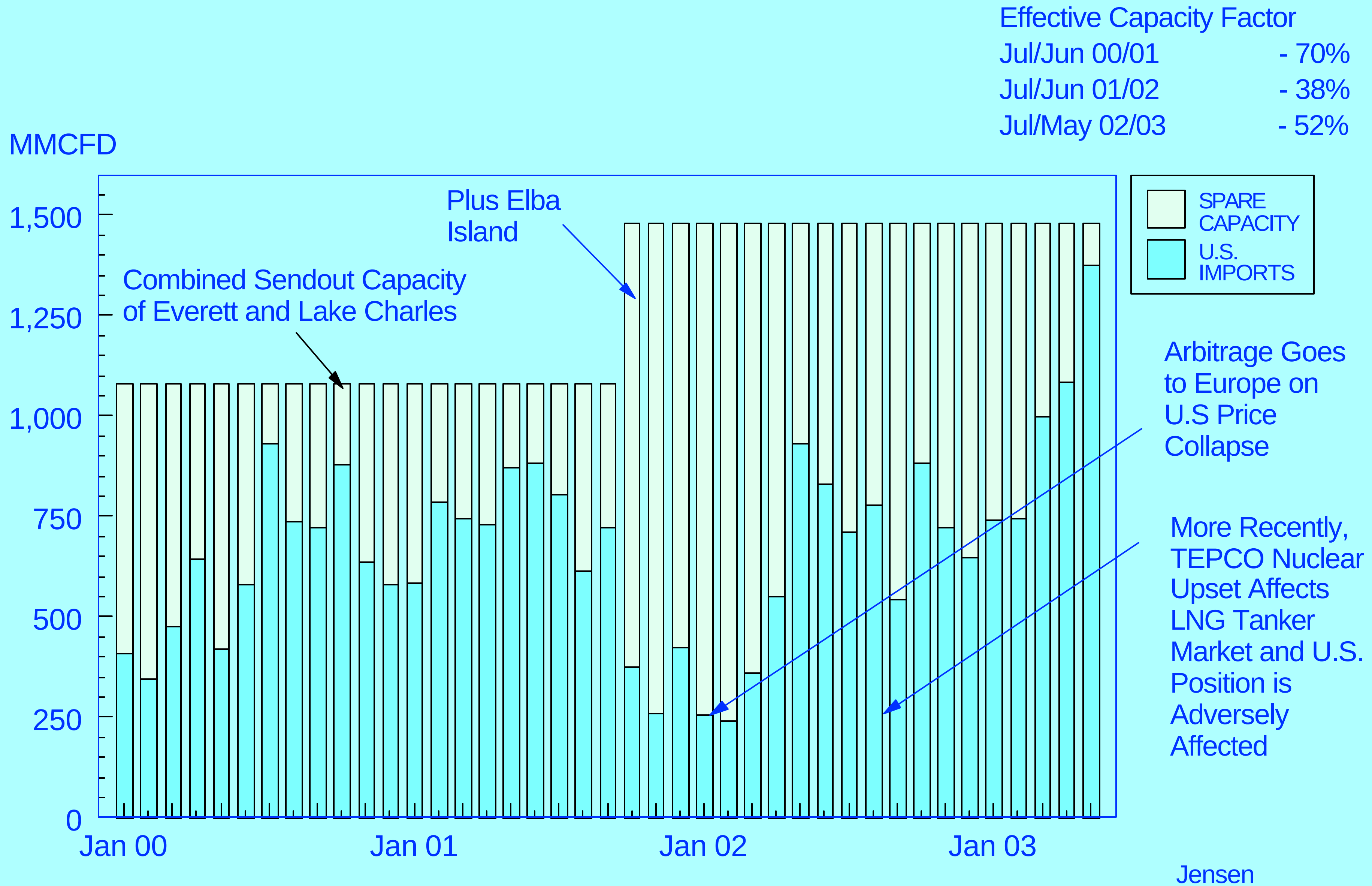

Figure 4

NETBACKS TO TRINIDAD, NIGERIA, AND QATAR LOADING PORTS FROM EUROPEAN, U.S. AND JAPANESE TERMINALS

SITUATION IN DECEMBER 2000 WHEN THE U.S. MARKET WAS VERY STRONG

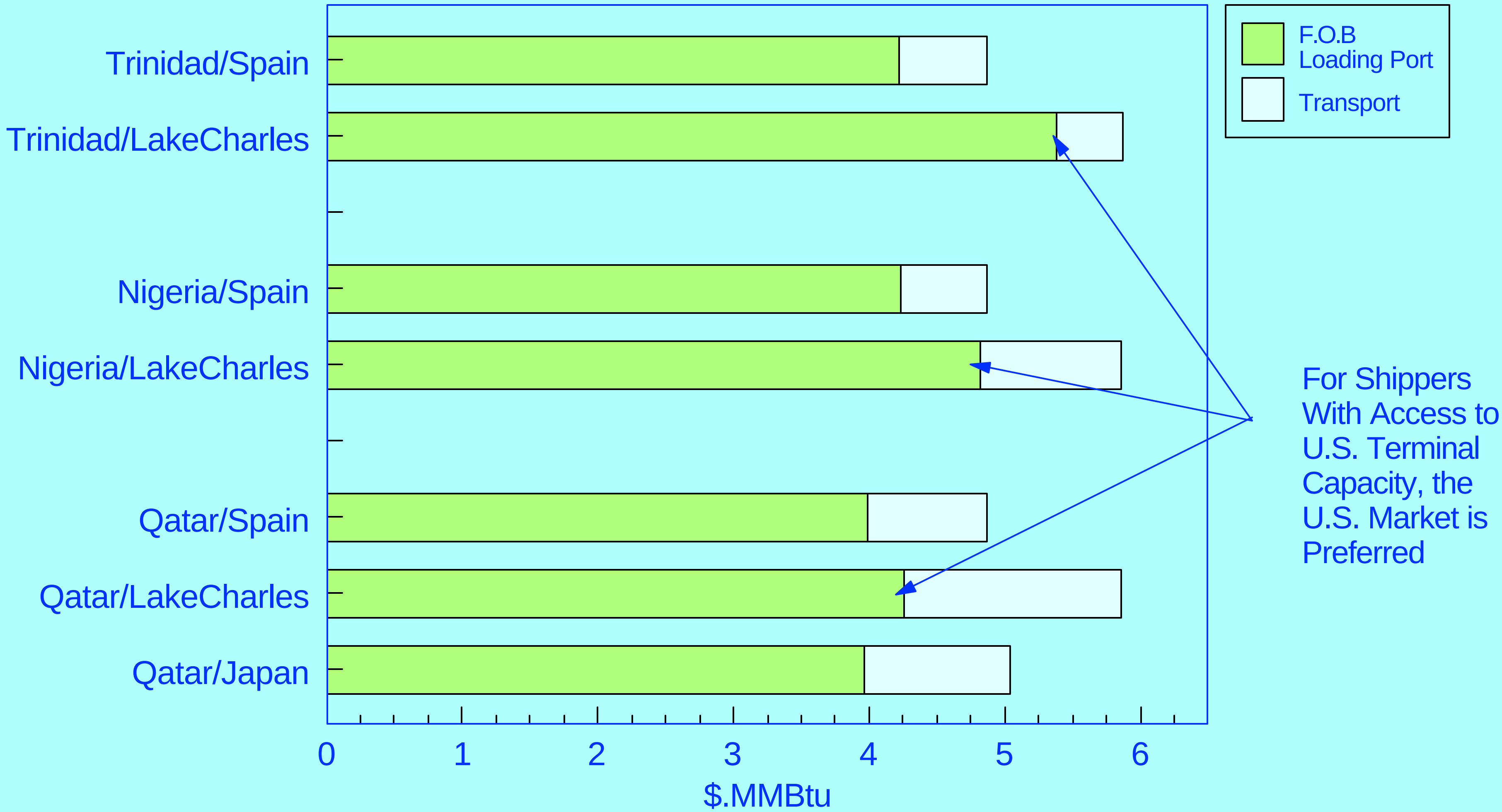

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Figure 5

NETBACKS TO TRINIDAD, NIGERIA, AND QATAR LOADING PORTS FROM EUROPEAN, U.S. AND JAPANESE TERMINALS

SITUATION IN SEPTEMBER 2001 WHEN THE U.S. MARKET WAS VERY WEAK

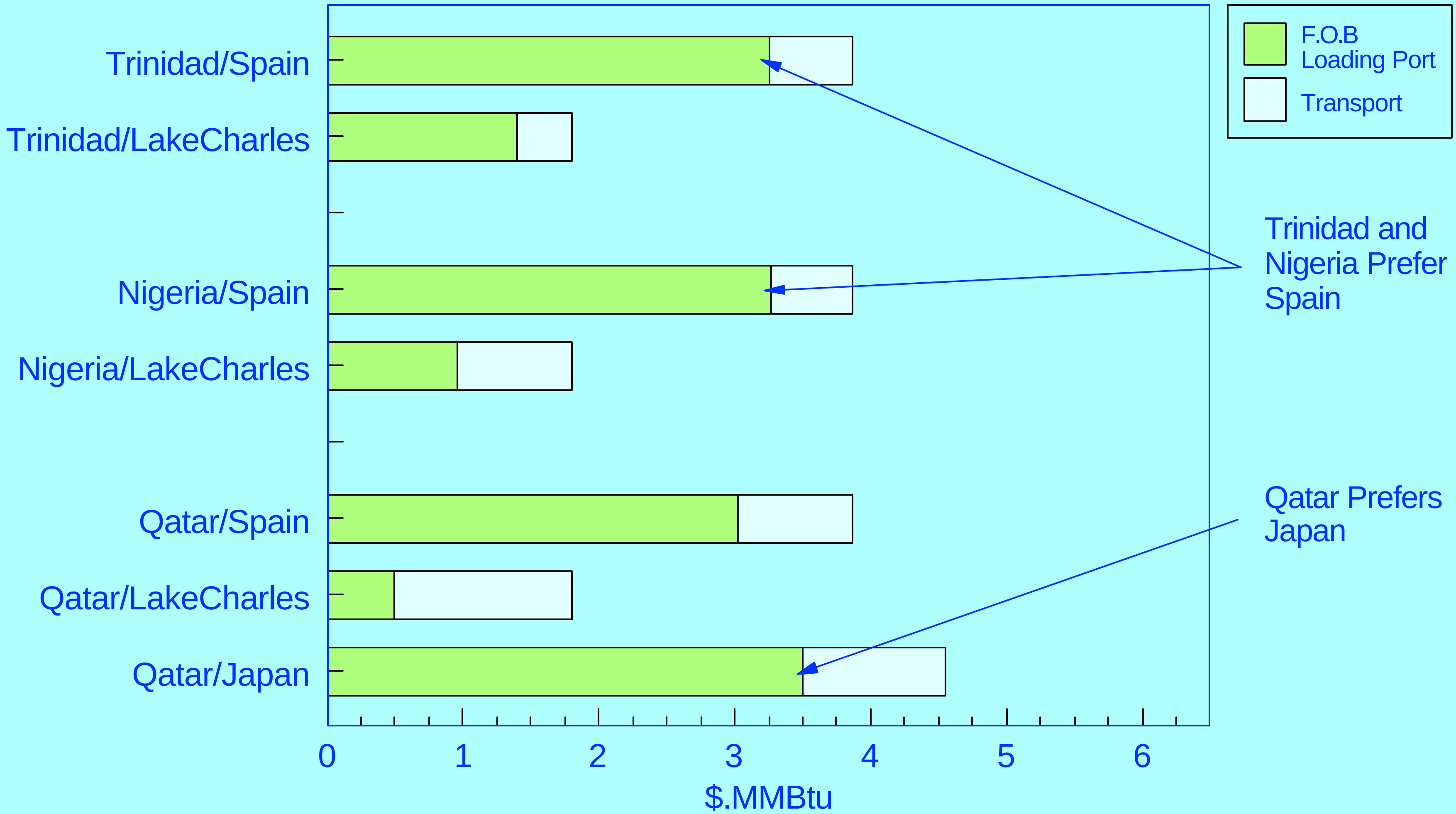

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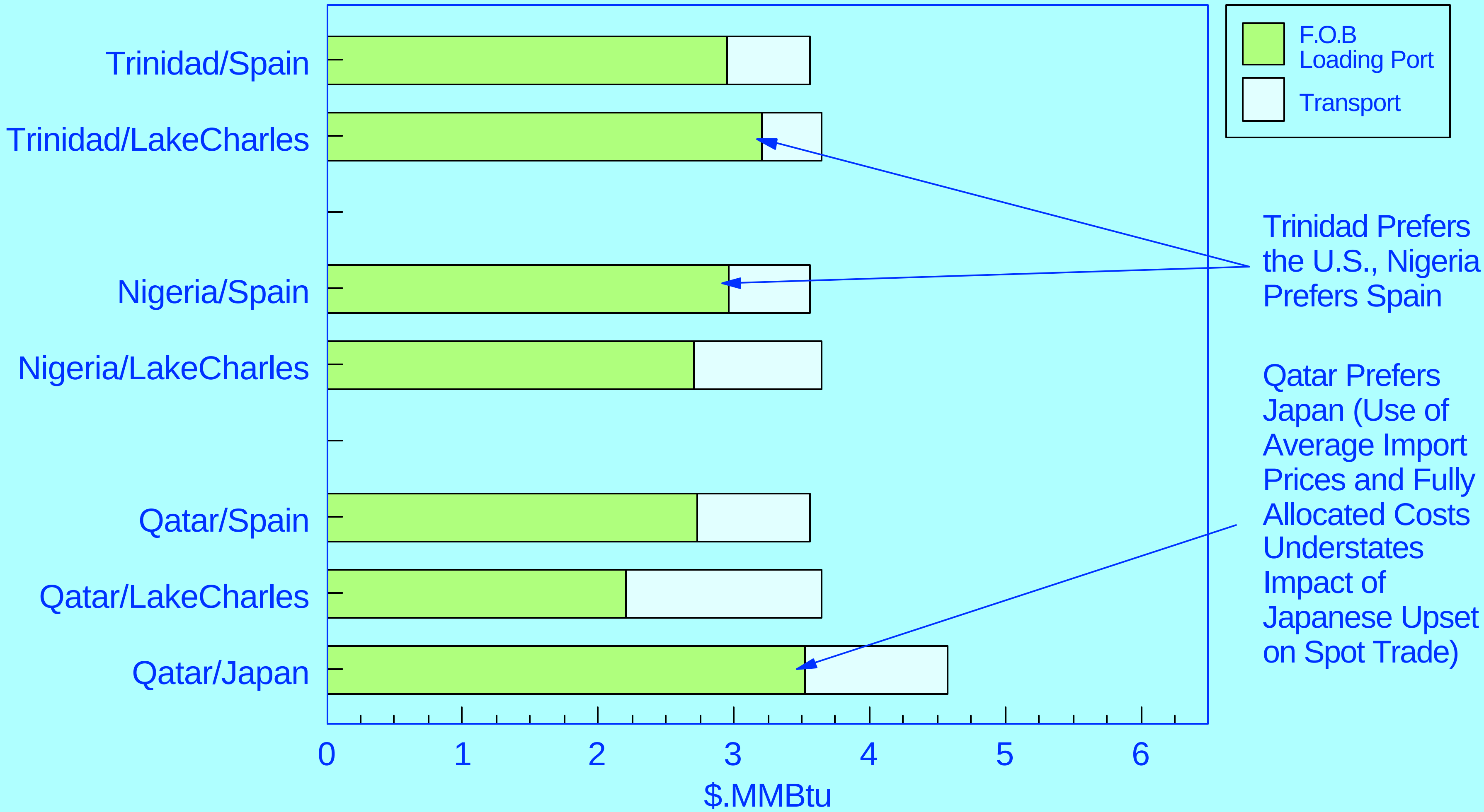
Figure 6

NETBACKS TO TRINIDAD, NIGERIA, AND QATAR LOADING PORTS
FROM EUROPEAN, U.S. AND JAPANESE TERMINALS
SITUATION IN NOVEMBER 2002 WHEN ASIAN MARKETS WERE VERY STRONG



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- While the Most Recent EIA Published Import Figures Suggest That U.S. Summer Imports are Recovering from the Tepco Upset, an August Fire at Malaysia's Tiga Plant May Put That Plant Out of Service for Six Months, Further Complicating the Asian Disruption of Short Term LNG Markets This Winter

- While it is Clear That the U.S. Cannot Import LNG If it Does Not Have the Necessary Terminal Capacity, the Converse - That Eliminating the Terminal Bottlenecks Guarantee LNG Supply - is Not Necessarily True

- Having Adequate Receipt Capacity Simply Gives the U.S. a Seat at the Table Enabling it to Compete With Europe and Asia for LNG Supplies

- And, Except for Trinidad, the Atlantic/Gulf U.S. is at a Transportation Disadvantage to Europe For Most Supply Sources

THE LNG BUSINESS HAS FREQUENTLY BEEN DESCRIBED AS A "CHAIN" WHOSE ULTIMATE SUCCESS IS AT RISK TO THE POSSIBLE FAILURE OF ITS WEAKEST LINK

- And Despite All of the Attention Being Paid to the Terminal Siting Issue, Terminals Are a Comparatively Small Part of the Total LNG Chain - They are the "Tail" - The "Dog" Is Upstream

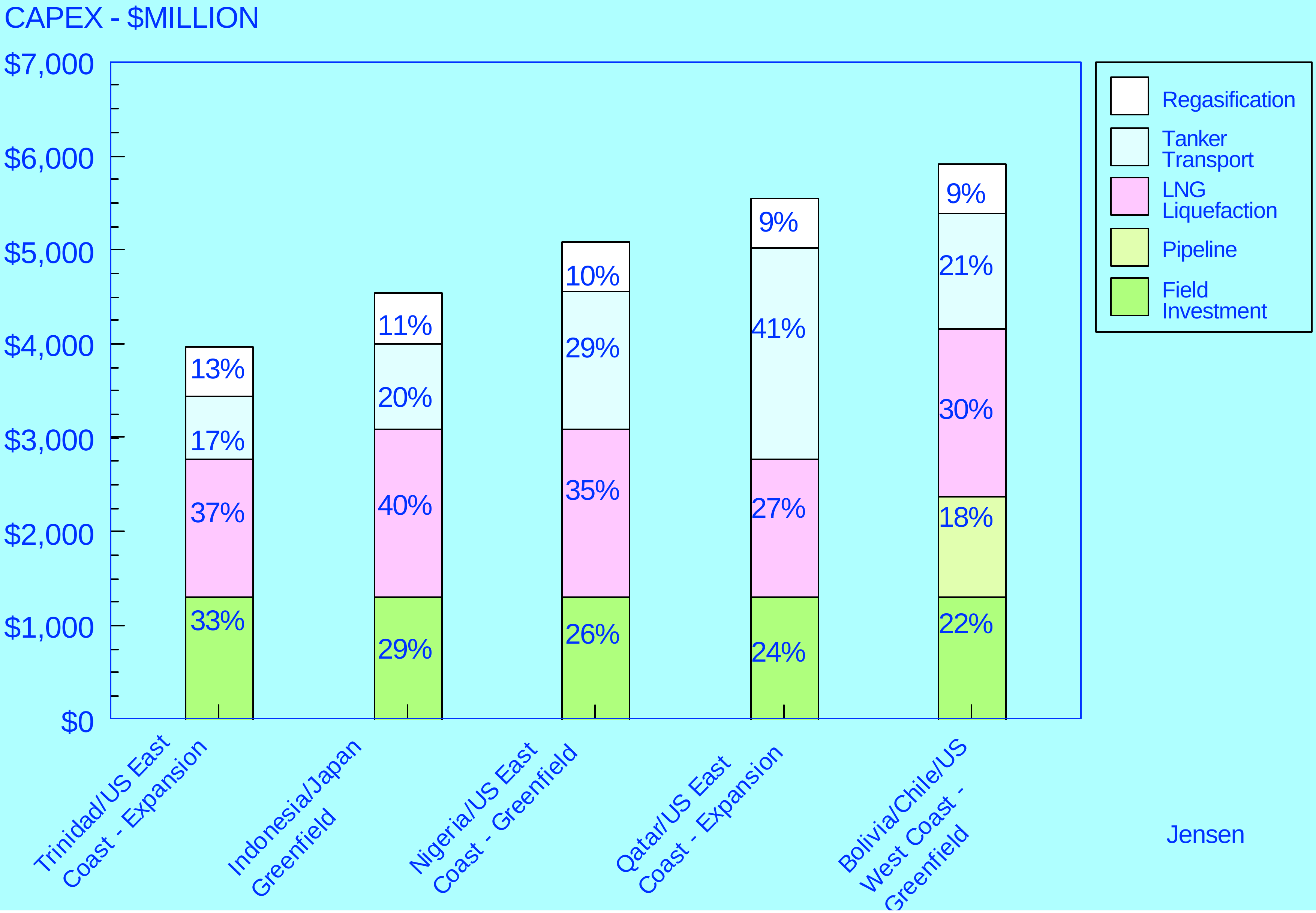
- Figure 7 Illustrates the Portion of the Capital Investment Required for Different Functions for Several LNG Trades

- The Terminal Portion of the CAPEX in the Illustration Varies from 9% to 13 % of the Total, the Field Development Portion Varies from 22% to 33% and the Liquefaction Portion from 27% to 40%

Figure 7

ILLUSTRATIVE CAPITAL EXPENDITURE PROFILES FOR SELECTED LNG PROJECTS

ASSUMING TWO 3.3 MMT TRAINS AND A FIELD INVESTMENT OF $3.85/ANNUAL MMBTU



- Upstream LNG Projects Are Characterized by Large Up Front Investments, Long Lead Times, "Lumpy" Supply Additions and Complex Negotiations Among the Various Stakeholders in the Project

- Prominent Among the Stakeholders are the Producing Governments (Where At Least Half of the CAPEX are Concentrated) Raising Questions of Political Risk, Not Only About the Stability of the Governments, But of Fiscal Regimes, as Well

- Thus LNG Projects Do Not Smoothly Respond to Short Term - and Volatile - Price Signals When Demand Calls for New Supply; New Investment Decisions Finalized Today Will Probably Not be On Stream Until 2007 or Later

- Traditionally, the LNG "Chain" was Held Together By a Comparatively Rigid Set of Long Term Contracts Featuring the "Sale and Purchase Agreement" or SPA

- The Risk Sharing Logic of the SPA Was Embodied in the Phrase ... "The Buyer Takes the Volume Risk and the Seller Takes the Price Risk"

- Hence, Contracts Typically Included a Take-or-Pay Provision to Insure Buyer Offtake at Some Minimum Level and a Price Escalation Clause to Transfer Market Price Uncertainty to the Seller

- In Addition, Since Buyers Were Commonly Regulated Utilities or Government Monopoly Companies, They Were Able to Lay Off Much of the Volume Risk to Their Ratepayers

- This Rigid Contract Structure Has Been Eroding for Some Time as Companies Have Been Willing to Commit to New Upstream Investments Without Fully Committed Trains

- Some Large Producers Have Also Contracted With Their Own Marketing Companies, Thus Effectively Integrating Downstream and Keeping Their Destination Options Open

- As a Result, an Active Short Term Market Has Developed (Still Only About 10% of World LNG Trade in 2002) But No New Train Has Yet Been Built Without Some Portion of its Output "Anchored" by Long Term Contracts

- For a Number of Reasons, This Pattern is Likely to Remain; The Need for Contract Commitments is Likely to Constrain the Size of the Short Term Market and Continue to Serve as a "Filter" in Determining the Flow of

- Now, In the Atlantic Basin - For the First Time - This Traditional Contract-Dependent Structure is Confronting a Restructured Gas Industry Whose Logic Presumes that Gas Markets are Workably Competitive and That Commodity Competition, With its Often Volatile Short Term Price Behavior, is the Most Effective Model for the Industry

- This Clash of Structural Models for the LNG Industry Has Substantially Shifted the Balance of Risks and Rewards Among the Parties in Ways that are Not Yet Fully Understood

- The Long Term Contract Gave Sellers the Assurance That They Had Secure Outlets Without the Need to Integrate Downstream as the Industry Has Traditionally Done in Oil

- However, it Appears That It is Increasingly Difficult to Find Buyers Who Can Deliver on the Traditional Volume Commitment (An Obligation Tied to a Gas Market Indicator is Substantially Weakened Since It is So Easy to Lay Off In the Market; And the Captive Ratepayers are Largely Gone)

- Hence, a Significant Part of the Market Risk Appears to Have Migrated Upstream, and Political Risk Has Never Really Gone Away

- While the Growing Diversity of Supply Sources Tends to Insulate Buyers from These Political Risks, Sellers With Investments in Affected Countries Can Only Spread the Risks by Investing in a Portfolio of Supply Sources

- In the Face of These Market and Political Risks, Integrating Downstream and Creating a Diversified Supply Portfolio Would Seem to Make Good Sense as a Producer

- The Problem is That the Price Tag for the Highest Degree of Diversity is So Large That Few Companies Can Afford It

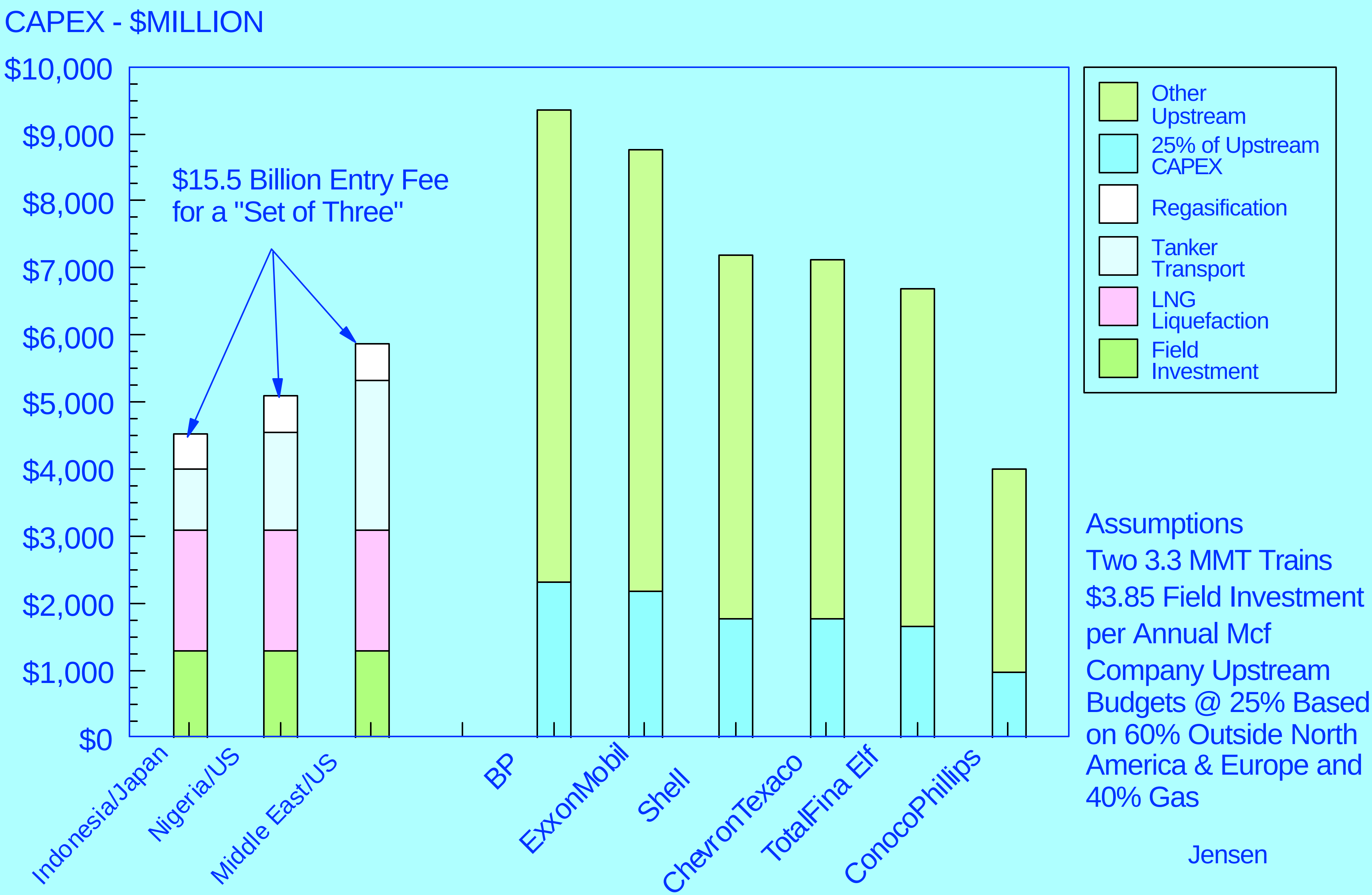
- Figure 8 Compares a "Greenfield Entry Fee" for What Might Be Described as a Fully Diversified LNG Portfolio to the 2001 Capital Expenditures of the Five Super Majors - the "Five Sisters" - (Together With the Smaller ConocoPhillips; BG is Also a Major Player But Difficult to Compare With the Upstream Oil Producers)

- After Adjusting the Budgets for Other Upstream Investments, the "Entry Fee" Remains Large Compared to Available Investment Dollars

- While There Will Be Many Individual "Niche" Opportunities For Other Companies in This Growth Business, It is Not for the Faint of Heart or the Undercapitalized

Figure 8

THE GREENFIELD LNG PROJECT "ENTRY FEE" COMPARED TO THE UPSTREAM 2001 CAPEX BUDGETS OF SELECTED COMPANIES



TRADE PRESS REPORTS OF LNG PROJECT ACTIVITY COMMONLY GIVE THE IMPRESSION THAT POTENTIAL LNG SUPPLY IS VIRTUALLY UNLIMITED

- But LNG Observers Have Learned to be Highly Skeptical About Such Plans, Especially About Their Timing

- Schedule Slippage is Routine Because the Complexity of Negotiations Commonly Causes Delays

- And the Highly Competitive Nature of Rival Projects Encourages "Gaming" Among Participants

- LNG Projects Operate Somewhat Like a Game of Musical Chairs; Those Left Standing Without a Contract or an Essential Partner Often Defer or Even Abandon Their Projects

- As an Example, a Recent World Gas Intelligence Listing of North American Terminal Proposals (Including Those Sited in the Canadian Maritimes, the Bahamas or Mexico Destined for U.S. Markets) Indicates a Total Capacity That is Nearly Two and One Half Times the EIA's Projected Increase in Total Gas Demand Between 2001 and 2010 (Figure 9)

- And WGI Lists Nearly Three Times the Capacity that a Similar EIA Estimate Showed Only Two Years Ago

- While No One Expects That Most of These Proposed Projects Will Ever See the Light of Day, It Does Illustrate How Much "Gaming" Goes on in Competitive Project Proposals in the LNG Business

Figure 9

CAPACITY OF PROPOSED NEW NORTH AMERICAN TERMINALS COMPARED WITH ESTIMATES OF DEMAND GROWTH - 2001/2010

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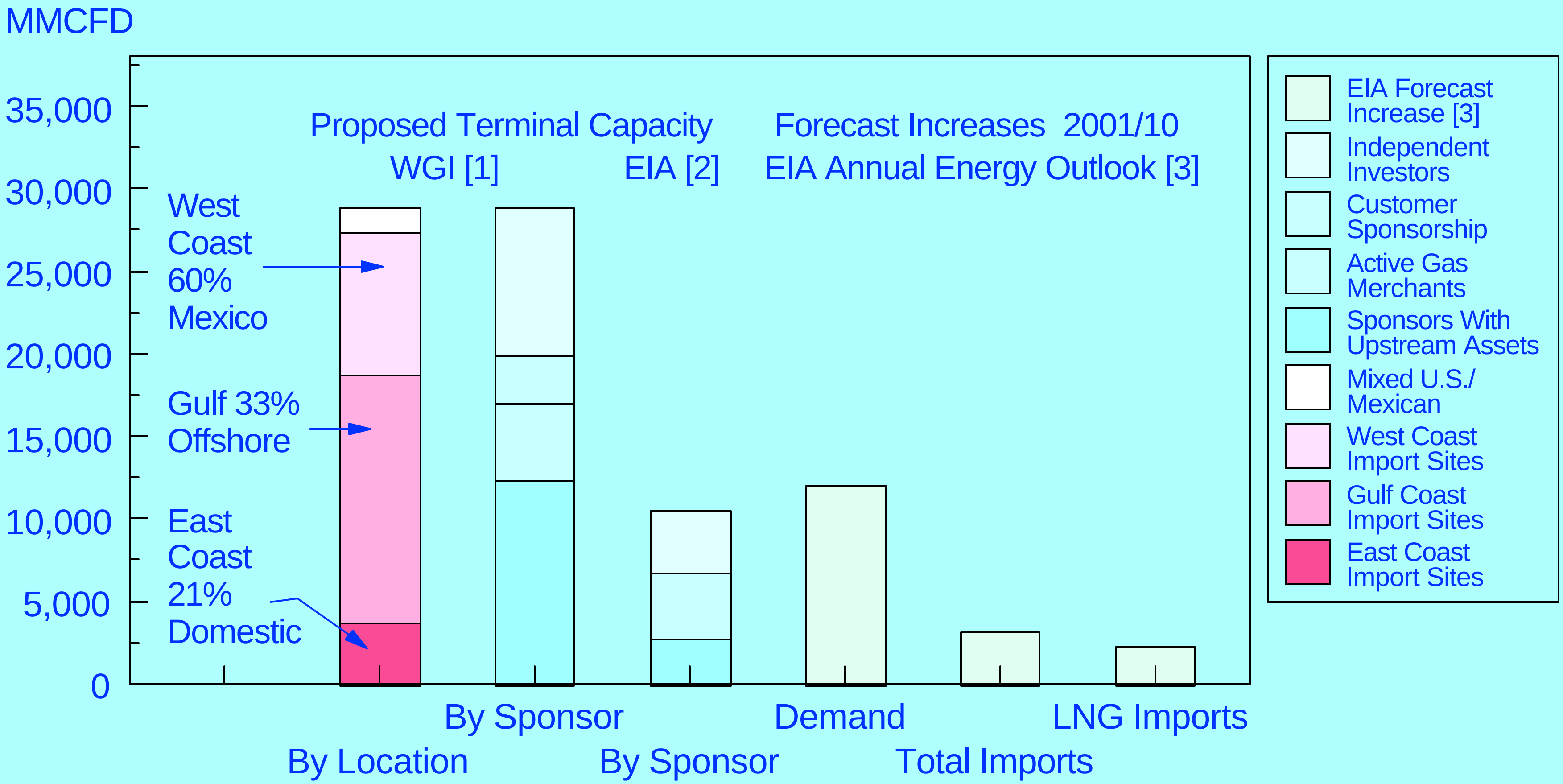

[1] Barbara Shook, World Gas Intelligence 9/17/03

[2] EIA - U.S. Natural Gas Markets 12/01

[3] EIA Annual Energy Outlook 2003 Forecsts

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ANNOUNCED PROPOSALS FOR NEW LIQUEFACTION PROJECTS HAVE ALSO USUALLY BEEN OVERLY OPTIMISTIC

- Because They Are Usually Joint Ventures and Because They Are Large Compared to the Partners' Capital Budgets, it is Often Difficult to Get a Final Agreement

- In Addition, Some Major Companies Have More Than One Entry in the Horse Race; As One Company Executive Once Remarked About a Particular Project, "We Can't Afford to Walk Away from that Situation, But We Certainly Hope Nobody Moves Very Fast on It"

- And Because Governments are Stakeholders, LNG Projects Are Usually Politically Complicated; Political Problems Have Been in the News this Past Year About Such Potential LNG Suppliers to the U.S. as Bolivia, Indonesia, Nigeria, Peru and Venezuela

- Hence, Many of the Projects Will Not Meet Their Publicized Schedules or May Even Be Abandoned Altogether

- Many LNG Market Watchers Classify Potential New Supply Projects According to the Likelihood of Their Becoming Commercial

- Figure 10 Shows One Such Classification Broken Down by Region, as Well as By "Firm", "Probable" and "Possible" Rankings; a "Remote" Category is Not Included

- Until the Recent Burst of Enthusiasm for New Projects, New Commitments Were Averaging 4.2 MMT (Equivalent to One Large Modern Train) Per Year; From1998 to 2002, that Average Rose to 7.8 MMTPY

- Firm Projects Are Scheduled to Add an Average of 5.6 MMTPY by 2010: Adding in the Probable Group Increases the Average to 11.9 MMTPY

- And if One Were to Take the Possible Group and its Publicly Stated Schedule Seriously, Additions Would Rise to 24.9 MMTPY, Implying a Capital Outlay in the Vicinity of $16 - $20 Billion Per Year

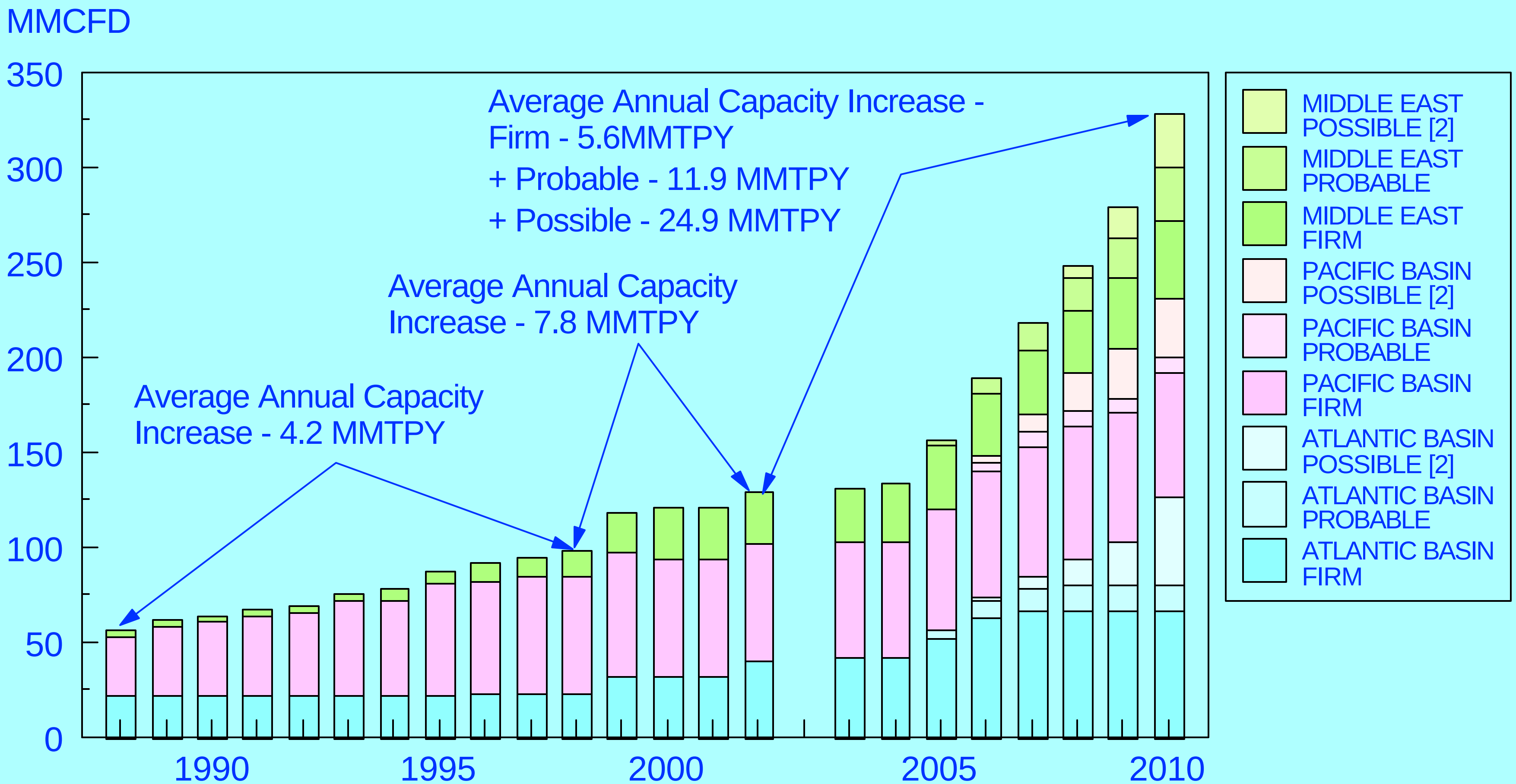
- The Best Way to Track the Likely Availability of Supply, Recognizing the Possibility of Schedule Slippage, is to Maintain a List of Contract Commitments

- Figure 11 is Such a List for the Atlantic Basin and the Middle East (the Pacific Basin is Not Shown)

Figure 10

HISTORY AND FORECAST [1] OF POSSIBLE LNG LIQUEFACTION CAPACITY BY REGION

MMT



[1] Jensen Estimates

[2] Placing Unscheduled Possibles in 2010

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Figure 11

REGIONAL DESTINATION OF NEW LNG CONTRACT SUPPLIES FROM OPERATING, "FIRM" AND "PROBABLE" [1] LIQUEFACTION PLANTS IN THE ATLANTIC BASIN AND THE MIDDLE EAST

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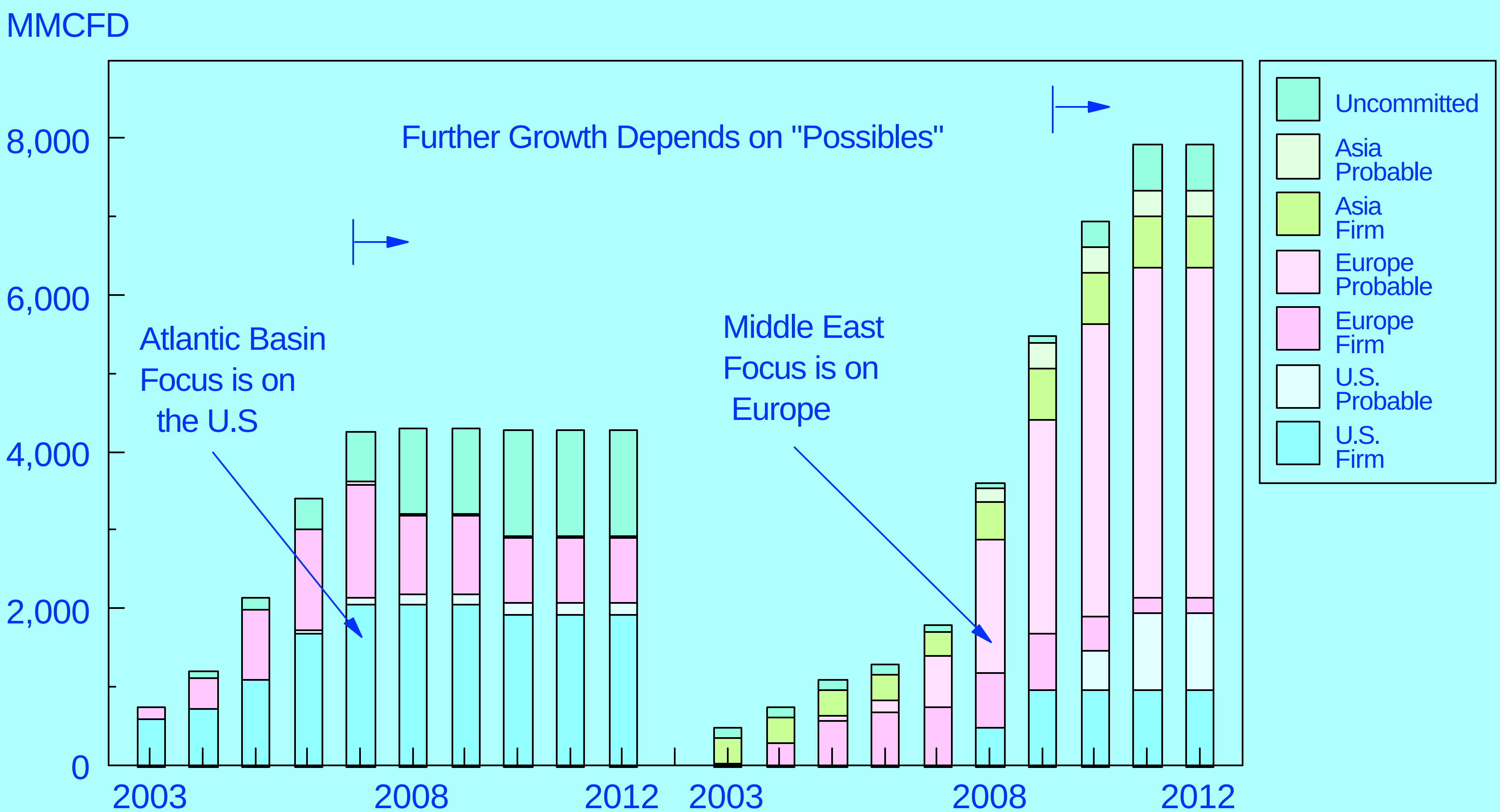

[1] Jensen Estimates Assuming Current Schedules

ATLANTIC BASIN MIDDLE EAST

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- The Principal Market Focus of Atlantic Basin Projects is on North America; the Middle East is on Europe
- One of the New Features of the Contract Process is the Availability of Uncommitted Volumes; These Can be the Result of Inherent Contract Flexibility, Developers Proceeding Without Full Train Commitments, of Contract Expirations, or Sales to the Companies' Own Marketing Organizations as a Means of Downstream Integration
- The Newer Integrated Sales Volumes are Most Prominent in the Atlantic Basin Where U.S./European Arbitrage is Common; They are Largely Absent in the Middle East, and Just Beginning to Appear in Asia
- Interestingly Enough, Except for One New Middle East Train, All New Train Commitments to the U.S. Also Include European Commitiments, Demonstrating the Producers' Desire to Hedge Their Exposure to the U.S.

- The EIA Annual Energy Outlook Projections Have Been Steadily Increasing Their Reliance on LNG (And the 2004 Forecast is Expected to Continue the Trend)

- The Contract Volumes Dedicated to North America (But Excluding Uncommitted Volumes) Fall Slightly Short of the EIA 2003 LNG Import Projection, But are Greater Than the 2010 Projection (Figure 12)

- Thus There Appears Little Upstream Problem, Assuming Timely Construction of Receipt Terminals, in Meeting or Exceeding the EIA's Projections

- While This Represents a Very Substantial Growth, Firm Plus Probable Volumes Still Consititute Only 6.3% of Projected Total U.S. Gas Demand in 2010

Figure 12

LNG CONTRACTUAL DEDICATION TO U.S. MARKETS FROM OPERATING, "FIRM" AND "PROBABLE" [1] LIQUEFACTION PLANTS COMPARED WITH ACTUAL AND FORECAST IMPORT LEVELS (DOES NOT INCLUDE UNCOMMITTED VOLUMES)

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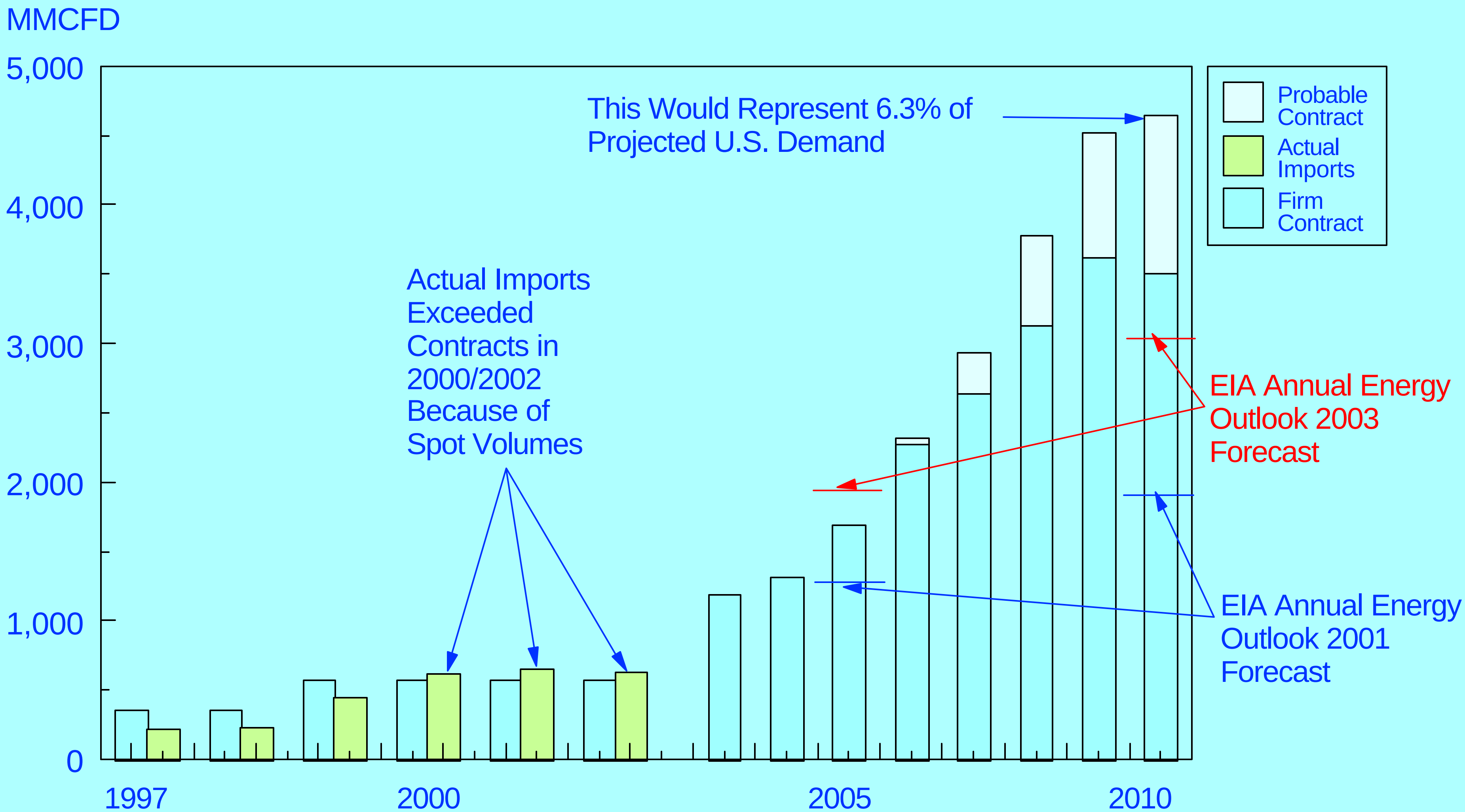

[1] Jensen Estimates

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TRYING TO PICK WINNERS AMONG THE MANY TERMINAL PROPOSALS IS MUCH MORE CHALLENGING

- In the Atlantic Basin, Terminals in the Northeast Are Heavily Favored Economically

- An Active Atlantic Basin Arbitrage Market Has Developed in Recent Years, Principally Involving Supplies from Trinidad, Nigeria and Algeria Trading Off the U.S. Terminals Against Spain and Belgium in Europe

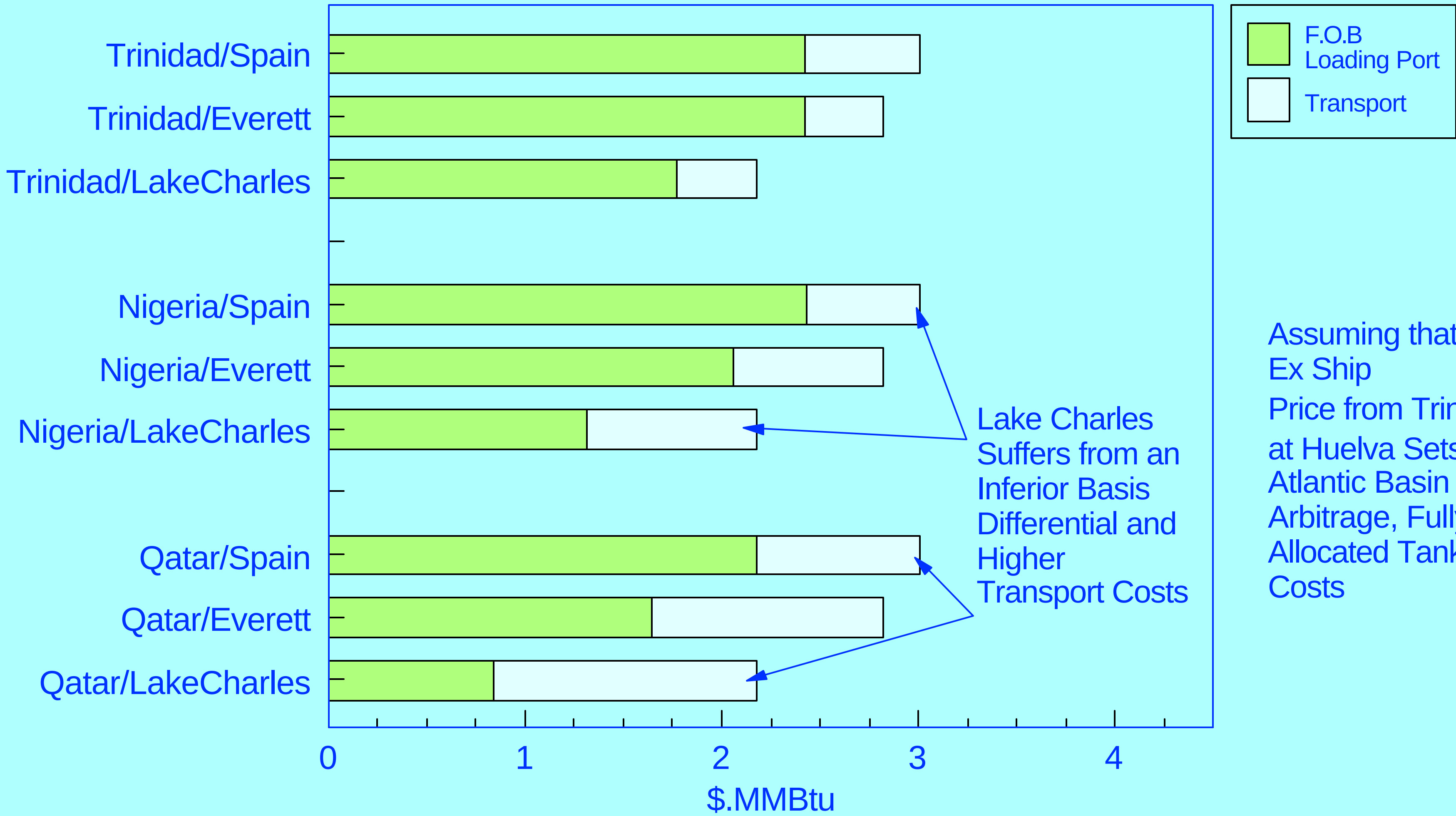
- Everett, Like Other East Coast Terminal Sites, Usually Provides a Better Netback Than Lake Charles on the Gulf Coast, Since (1) It Enjoys a Significant Basis Differential Over Henry Hub Prices, and (2) It is Closer to Most LNG Suppliers, Thereby Minimizing Transport Costs

- Figure 13 Illustrates the Effect on the Netback (As Liquid) to the Loading Port of the Combined Basis Differential and Transport Saving for Three Different Supply Sources

Figure 13

NETBACKS TO TRINIDAD, NIGERIA, AND QATAR LOADING PORTS FROM SPANISH AND U.S. TERMINALS

ASSUMING THAT A $3.00 EX SHIP DELIVERY FROM TRINIDAD TO HUELVA, SPAIN IS ARBITRAGED AGAINST A TRINIDAD DELIVERY TO EVERETT



Assuming that a $3.00 Ex Ship Price from Trinidad at Huelva Sets the Atlantic Basin Arbitrage, Fully Allocated Tanker Costs

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THE APPEAL OF THE DOWNSTREAM BASIS DIFFERENTIALS AND SHORTER TRANSPORT HAULS ARGUES FOR NEW TERMINAL SITING ON THE EAST COAST

- Unfortunately, It Has Proved Extremely Difficult to Gain Siting Approval for Such East Coast Locations Because of Local Popular Resistance

- Therefore, Atlantic Basin Terminal Options Seem to Have Settled on Three Different Alternatives
  1) Gulf Coast Locations Where the Long History With Oil/Chemical Sites Minimizes Local Opposition
  2) Foreign Locations, Such as Nova Scotia, New Brunswick, the Bahamas or Mexico, Where Siting Approvals May Be Easier to Obtain But the Gas Must Be Further Moved by Pipeline
  3) Offshore, Where Environmental Approvals are Less Stringent

THERE ARE PLUSES AND MINUSES WITH EACH OF THESE ALTERNATIVES

- While They Are Easier to Approve and Integrate Into the Pipeline Grid, The Gulf Coast Terminal Options Forfeit the Basis Advantage and the Shorter Distance From Sources

- The Foreign Locations Lose Some of their Basis Advantages Through Onward Pipelining and They Can Easily Overload Local Markets With Negative Pricing Consequences

- The Offshore Locations Have Come into Greater Favor With the November 2002, Enactment of the the Deepwater Port Act Amendment (DWPA), Which Shifts Regulatory Responsibility for Offshore LNG Facilities from the Federal Energy Regulatory Commission to the Maritime Administration and the U.S. Coast Guard.

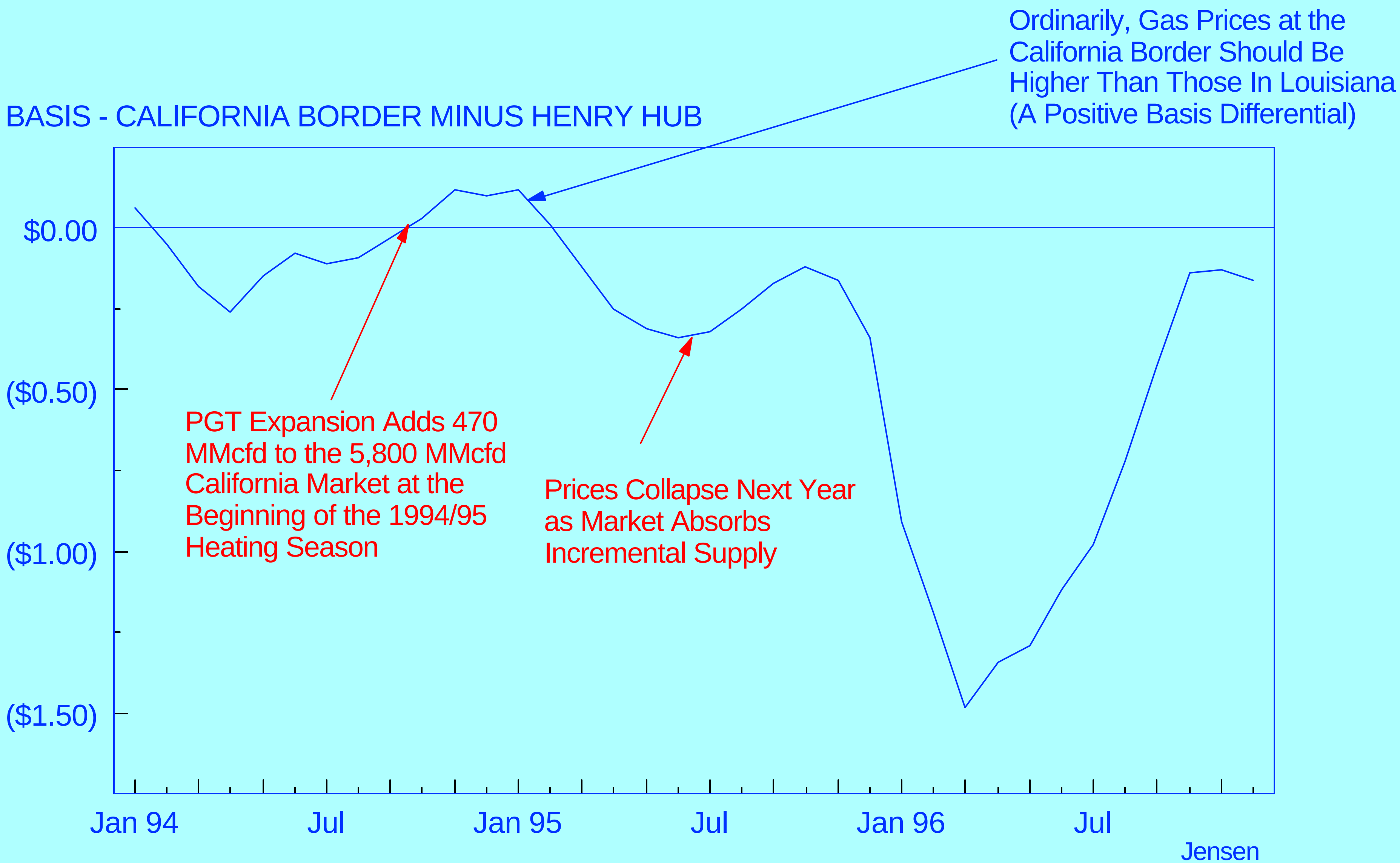
- The Early Proposals Were Heavily Oriented Towards Gas Trading Companies Without Upstream LNG Assets
- However, the Difficulties of Enron, Dynegy and El Paso Have Shifted Some of the Emphasis Away from This Group
- FERC's "Hackberry" Decision Which Enabled Companies to Control Proprietary Terminals Without Open Access Has Brought the Integrated Companies More to the Fore
- Some of the Remaining Independents are Either Featuring Downstream Customer Commitments or Are Prepared Simply to be Investors, Tolling Throughput to Those Who Control the Upstream Supply

- For the California Market, there are Similar Siting Problems to Those of the Atlantic
- The Most Popular Option is a Site in Baja California for Reexport to Southern California, But Several Small Onshore Sites and One Offshore Site Are in the Running
- However, California is Remote from Most Existing Supply Sources and it is a Market That Can Easily Be Overloaded, Thus Introducing the Concept of "Basis Risk" into the Feasibility Analysis
- California's Experience with the Expansion of the Pacific Gas Transmission System from Alberta in 1994 Illustrates the "Basis Risk" Issue (Figure 14)
- Thus the West Coast Terminals Pose Their Own Special Problems

Figure 14

"BASIS RISK" - COLLAPSE OF THE CALIFORNIA BASIS DIFFERENTIAL FOLLOWING THE 1994 EXPANSION OF PACIFIC GAS TRANSMISSION

THREE MONTH MOVING AVERAGE



IN CONCLUSION

- LNG Finally Seems Destined to Play a Very Substantial Role in North American Gas Supply Over the Next Few Years

- The Growth in Power Generation Demand, the Supply Problems Confronting Traditional North American Supply, the Widespread Availability of International "Stranded Gas" and the Industry's Demonstrated Ability to Reduce Costs, All Point to Signifcant Growth for LNG

- But it is Important to Keep the Optimism in Perspective

- The Real Governing Force for LNG Growth is Upstream, Where the Largest and Riskiest Investments are Concentrated; This Tends to be Major Country Territory Where Host Government Politics Play an Important Role

- And Despite an Active Short Term Market, the Long Term Contract is Not Dead and Will Exert a Subtantial Degree of Control on LNG Supply, a Factor that Will be Particulary Important in North America Where a Restructured Market is Challenging the Traditional Terms of Trade

- And Finally, LNG Will Not Place a "Cap" on U.S. Gas Prices

- Its Influence on Price Will be Manifested in How Much and How Quickly Supply is Competively Made Available to Shift the Supply/Demand/Price Curve