TRENDS IN PROJECT FINANCING AND DEREGULATION IN THE U.S. POWER MARKET IN THE AFTERMATH OF THE CALIFORNIA AND ENRON CRISES

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I. DEREGULATION IN THE UNITED STATES – OVERVIEW

A. Traditional Regulatory Compact

1. Geographic monopoly: Utilities were granted the exclusive franchise to sell and distribute electricity within their service territories in exchange for (a) undertaking a universal obligation to serve and (b) charging retail rates that were subject to a reasonableness review by state regulators, which provided for a pass through of the utility's reasonably-incurred costs of power generation, procurement, transmission and distribution, plus a reasonable return on equity. Utilities primarily served local load, although they may have owned generation and transmission assets located outside of their service territories.

2. Vertical integration: Utilities provided bundled services, owning assets at all levels of the value chain (generation, transmission and distribution)

3. Extensive state regulatory oversight over all operations

4. Retail rates approved by regulators based on public policy priorities:

    a. System reliability through redundancy was favored over efficiency
    b. Stable rates were favored over low rates
    c. Nondiscriminatory access was assured
    d. Regulators required or permitted some cross-subsidization of certain classes of users, such as residential, commercial or industrial users, and of low income households
    e. Demand side management and conservation gained in 1970-1990s

5. Limited wholesale market for sales of electricity, primarily to balance regional grids and to move bulk power from distant generation sources

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6. Federal regulation relatively limited

    a. Cost of service based rates with regulatory rate of return; Section 204 of the Federal Power Act requires "just and reasonable rate" (16 U.S.C. § 824(d))
    b. There are limitations on Federal/FERC jurisdiction under the Federal Power Act (16 U.S.C. § 824(f)): Investor-Owned Utilities, Municipal Utilities, Electric Cooperatives, Federal Power Marketing Agencies
    c. Interstate holding companies are subject to regulation and SEC oversight under the Public Utility Holding Company Act of 1935 ("PUHCA")

B. *Trend since 1978: Deregulation and demonopolization to encourage efficiency through competition in wholesale electricity markets*

1. Power generation demonopolized by Public Utility Regulatory Policies Act of 1978, (6 U.S.C. §§ 2601 et seq.) ("PURPA"): In the wake of the second oil price shock of the 1970s, the Carter Administration sought to increase energy efficiency and competition by requiring utilities to purchase power from alternative energy producers and cogeneration facilities ("qualifying facilities" or "QFs") under long term power purchase agreements ("PPAs")

2. Wholesale sales of electricity at market-based rates under Federal and state laws

3. Energy Policy Act of 1992 (15 U.S.C. §§ 79z-5a)

    a. Exempt wholesale generators ("EWGs") allowed to operate
    b. Nondiscriminatory transmission access
    c. Merchant power plant market born
    d. States and FERC establish rules for competitive wholesale power markets

4. FERC's "Unbundling" and Open Access Transmission Initiatives

    a. Order No. 888 (1996): "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission by Public Utilities."

        i. Order seeks to achieve competition in free and open wholesale markets for electric power by requiring the separation of electric utilities' generation and transmission functions
        ii. Eliminates monopoly power

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iii. Functional "unbundling" of utility generation and transmission
iv. Utilities filed open access, non-discriminatory transmission tariffs containing minimum terms and conditions
v. Utilities take transmission service for their own wholesale sales under the open access tariff
vi. Jurisdiction over retail transmission: Supreme Court to rule on appeal of Order 888

b. Order No. 889 (1996): "Open Access Same-Time Information System and Standards of Conduct"

i. Open Access, Same-Time Information Systems (OASIS): Existing and potential customers have same access to transmission system information as utility companies
ii. Separate generation function and transmission function employees
iii. Separate communications of non-public information between generation function and transmission function employees
iv. Contemporaneous posting of shared information on OASIS
v. Problems:
    1) vertical integration: no structural reform
    2) utilities favor their own resources
    3) unbundling retail functions

c. Order No. 2000 (2000): "Regional Transmission Organizations"

i. Required all "public utilities" that own electric transmission facilities to file with FERC by October 15, 2000 either:
    1) a voluntary proposal to participate in an RTO, or
    2) an explanation for non-participation
ii. RTOs in formation
    1) Eastern Interconnection
    2) Western Interconnection/RTO West
    3) Tight Power Pools: Pennsylvania, New Jersey and Maryland (PJM), New York, New England
    4) Midwest RTO: PJM Letter of Intent
    5) Southeast (stymied by local opposition)
    6) California (state rejects participation in RTO West, which makes little sense without California)

d. Issues with RTO formation

i. Cost-Benefit Analysis

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ii. Standardized Market Design
iii. For profit vs. nonprofit Structure
iv. Growing uncertainty among utilities over whether the benefits of RTOs will justify the costs, loss of control.

e. FERC modifying position, expectations with respect to RTOs in light of regional disparities, California opposition, recent dislocation in power markets

f. New legislation may affect proposed RTOs

C. Deregulation is part of an ongoing discourse on shifting public policy priorities:

1. Reliability (redundancy; reserve margins)

2. Low retail prices (long run affordability)

3. Stable or predictable retail prices (short run affordability)

4. Efficiency (competitive response to price signals)

5. Diverse generation sources (for reliability and environmental reasons, and to mitigate fuel price volatility and fuel supply risk)

6. Incentives for new investment (now, usually market-based)

7. Green power (environmentally friendly, even at greater cost)

8. Demand side management (conservation fostered through regulatory incentives)

9. Economic development (subsidization)

II. DEREGULATION AND MARKET FAILURE IN CALIFORNIA

A. 1996: California enacts deregulation law (AB 1890) to create an open market by deregulating power generation

1. California Independent System Operator ("Cal-ISO") and California Power Exchange ("PX") established to facilitate wholesale spot market for electricity and to manage transmission and ancillary services;

2. freeze on retail rates imposed to allow utilities to recover stranded costs during transition period

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3. Expectation of lower prices due to competition in near term, new capacity additions planned in 1998-2000 to come online in 2001-2003

4. Transmission subject to FERC regulation

B. *1998: Deregulated market opens for business*

1. The three main investor-owned utilities ("IOUs") – Pacific Gas & Electric Company ("PG&E"), Southern California Edison ("SCE") and San Diego Gas & Electric ("SDG&E") -- sold their thermal-fired generating assets as required by AB 1890

2. Cal-ISO manages transmission assets of three IOUs, comprising about 75% of state's grid

3. PX market opens

4. Municipal utilities (SMUD, LADWP) opt out of deregulated market

C. *2000/2001: Market Failure and Collapse of Deregulation*

1. Weather--the "Perfect Storm": unusually hot summers; warm, dry winters; below average rainfall and snowpack, causing low reservoir levels and limiting hydropower resources; environmental constraints limit summer production (hydro and thermal).

2. Peak demand exceeded supply, even in winter and shoulder months, although California Energy Commission ten-year forecasts of capacity and load growth had been accurate.

3. Increased population growth in other Western States boosted demand for power that would otherwise have been exported to California.

4. "Wait and see" attitude proved fatal. Construction of new power plants stalled in the 1990s due to recession (1991-93), followed by long period of uncertainty about the shape of deregulation and the structure of the deregulated power market (1994-98).

5. Natural gas prices rose due to low winter storage levels and congestion in intrastate gas transportation and storage systems and on interstate gas pipelines.

6. Because retail electric rates were fixed, IOUs could not pass through volatile wholesale prices, which spiked unexpectedly to record high levels. Utilities could not recoup wholesale power cost increases from retail ratepayers. Massive borrowing to cover negative cash flow and

operating losses for the IOUs resulted from them paying more for each kWh they purchased in the wholesale market (on a blended basis) than they were able to charge their retail customers.

7. Lack of long term contracts resulted in all power purchases at spot market prices, inherently increasing volatility and credit risk.

8. Utility credit spiral increased costs, as generators refused to sell to them or added a credit risk premium, forcing (a) State intervention, as the CDWR purchased power for utility customers, and (b) action by the FERC to impose limited West-wide price caps and Cal-ISO buyer creditworthiness standards and to investigate alleged market abuses.

9. Bottlenecks in intrastate high voltage transmission lines (Path 15 and others) exacerbated the shortages and reduced the ability of Cal-ISO to prevent blackouts by shifting excess power from South to North.

D. Effect on PG&E and SCE

1. IOUs were directly affected by AB 1890

   a. Under AB 1890, PG&E divested itself of its thermal generating facilities, retaining its nuclear and hydropower plants.

   b. Because of a freeze on existing retail rates, PG&E could not recoup increases in wholesale power costs from retail ratepayers. By end of January 2001, the shortfall exceeded $8 billion.

   c. PG&E exhausted its ability to borrow additional funds and could not purchase all the power needed to serve its retail customers.

   d. SCE, the state's 2nd largest utility, was in a similar situation as PG&E, though it relied more on QFs, and it had higher rates and lower overall procurement costs.

E. State Response To Market Collapse

1. January 18, 2001: Following an emergency legislation, California Governor Davis approved Assembly Bill 6X; AB 6X essentially repealed AB 1890. The PX ceased operations and the Cal-ISO's management and responsibilities were overhauled under state control.

2. CDWR begins purchasing power on behalf of customers of PG&E and SCE, covering the "net short" position and running up billions of dollars in deficit spending for the state.

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3. April 6, 2001: PG&E filed under Ch. 11 of the U.S. Bankruptcy Code.

4. April 9, 2001: SCE signed an MOU with the State for the sale of SCE's transmission lines or a dedicated rate component, the proceeds of which were to be used to repay SCE's debts from past undercollections.

5. September 20, 2001: PG&E filed its Plan for Reorganization with Bankruptcy Court

6. October 2, 2001: CPUC and SCE settled Filed Rate case, which allowed SCE to keep surplus cash flow from rates to repay its debts outside of bankruptcy on terms more favorable to SCE than the MOU.

7. The contest between the CPUC and PG&E continues in bankruptcy court over their rival plans of reorganization, pre-emption of state laws under the U.S. Bankruptcy Code, the shape of future regulated entities, and tension between state and federal regulation.

F. *Observations*

1. Supply should improve this year and next, depending on weather (hydro resources), due to new capacity additions, including several fast-track gas-fired plants added in the past year or due online in the next year.

2. Long term contracts entered into by CDWR, by the California Power Authority, and possibly later others by the IOUs, should stabilize the supply/demand imbalance, so utilities can manage price and supply volatility while stabilizing generators' cash flows and providing a basis for new plants to be financed.

3. CDWR contracts are being renegotiated due to political pressures and drastic drop in spot market power prices in California and the West.

4. In the medium term, expect higher prices with lower volatility, but long term prices should decline due to new supply and mix of sport and forward markets if deregulation is reinstated in modified form.

G. *Effects of California market failure on other U.S. markets*

1. Political will for deregulation damaged.

2. Refined forecasting is needed to better measure demand growth, to analyze downside scenarios, to reset forward price curves for electricity and natural gas, to measure benefits of reducing risk through long term contracts and other hedge mechanisms, and by regulators to ensure sufficient reserve margins can be maintained.

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3. Considerable slow down or "wait-and-see" attitude by regions that are considering or have initiated their own brand of deregulation, and maybe in states that have put deregulation on hold.

4. Ongoing battle between some state regulators and FERC.

III. ENRON BANKRUPTCY

A. *Enron Corporation: Once "The Company to Invest In."*

1. Ambitious vision and practices of Enron:

a. Aggressive acquisitions and new trading ventures were viewed as high priorities for Enron to expand quickly and to capture and dominate new markets.

b. Enron had big plans for creating open markets in which to broker energy, bandwidth, advertising time, and novel "new economy" commodities.

c. Shift away from hard assets to "virtual" assets, to maximize optionalities in fast-moving markets.

2. What went wrong:

a. Some assets (including some foreign assets) acquired or developed by Enron underperformed expectations and led to operating losses for those business units, many of which were off-balance sheet.

b. Enron's share price reflected its ambitious growth expectations, rather than current-year asset value or cash flow, so that the premium embedded in the stock price became a deep discount once doubts about the company and the veracity of its financial statements spread through the market.

c. Public disclosures may have masked operating losses or asset values, either because of off-balance sheet treatment or inclusion in financial reports of other business units.

d. A combination of greed and hubris postponed but aggravated Enron's fall.

B. *Reaction in Washington and Effect on Energy Markets*

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1. The SEC, more than 10 Congressional committees and subcommittees, and various states (including California) are investigating various aspects of Enron's business, its management (including possible conflicts of interest) and its audit, financial reporting, disclosure and document handling practices.

2. Many members of Congress are unwilling to separate Enron-related issues from electricity policy discussions, although other public policy issues (*e.g.*, campaign finance reform, accounting standards, corporate governance, securities laws) are implicated at least as much by the investigations and calls for new legislation or oversight.

3. Energy markets only minimally reacted to Enron bankruptcy and interruption of trading at Enron Online, and the lack of any immediate dislocation in commodity markets (like energy) that Enron previously dominated shows the robustness of those markets.

4. Market players are taking even greater efforts to measure, price and hedge counterparty risk in trading activities, as well as the systemic risk inherent in multilateral trading networks.

IV. REGIONAL VARIATIONS AMONG U.S. POWER MARKETS

A. Northeast Region

1. New York

   a. Deregulating
   b. Utilities allowed to enter into long term PPAs to hedge spot market price volatility and reduce credit risk, but must retain some exposure to variable, short-term power or fuel costs to encourage competition and market price signals
   c. NYC utilities (Consolidated Edison Co. of NY and Long Island Power Authority) have local reserve margin requirements (18% min.) to mitigate price risk from severe transmission constraints

2. PJM (Mid-Atlantic)

   a. Adequate power supply: reliable, stable and diverse
   b. 19% minimum reserve margin for Load Serving Entities
   c. 40,000 MW of new capacity planned for next decade
   d. Most major utilities mitigated price and volume risk through long term PPAs with generation affiliates (Baltimore Gas & Electric, PEPCO, Public Service Electric & Co., PPL Electric Utilities Corporation, etc.) and have trading affiliates

e. GPU Inc.'s subsidiaries (Metropolitan Edison Company and Pennsylvania Electric Company) unhedged their provider of last resort ("POLR") risk. In June, 2001, the Pennsylvania Public Utility Commission gave regulatory relief allowing deferral of energy costs

3. NEPOOL (New England Power Pool)

    a. Reserve margin may climb from 4% in 1998 to 70% by 2002: overcapacity in generation assets may lead to early retirement of older, less efficient or dirtier plants as new plants come online
    b. Summer peak to grow at 3% per year from 21,406 MW in 1998 to 24,046 MW in 2002. At the same time, installed generation projected to increase from 22,263 MW to over 40,000 MW
    c. Transmission constraints will counter price benefits from overcapacity (service into Boston affects pricing there; bottlenecks limit imports from Hydro-Quebec system)
    d. Gas supply and transportation are insufficient for all new and planned capacity to become operational
    e. Early and advanced deregulation:

        i. retail choice
        ii. direct access
        iii. retail price caps subject to adjustment by regulators if fuel prices rise
        iv. utilities retain POLR risk

B. Northwest Region

1. Subject to higher gas prices and hydro resource variability

2. Rapidly growing population offset by recently slower economic growth

3. Unlike California utilities, almost all utilities in the Northwest Power Pool (i) still own most of their own generating assets, (ii) have long term contracts and (iii) can pass costs through to retail ratepayers

4. Regulatory support to ensure continued access to capital to maintain liquidity and cash flow in face of capacity constraints

5. Region dominated by BPA

6. Environmental laws (such as rules designed to protect fish in rivers) affect operations of hydro assets

C. Southeast Region

1. No deregulation, except for Virginia (structured similar to Texas)

2. 21,000 MW of new capacity to be added from 2001 through 2005 (according to the North American Electric Reliability Council)

3. Florida dominated politically by utilities hostile to deregulation, imposing significant barriers to entry on non-utility generators

D. Midwest Region

1. Stable supply/demand balance

2. Steady and slow demand growth

3. Legacy of low cost coal-fired plants and nuclear power plants

4. Proximity to low cost Canadian hydro resources

5. Few transmission constraints relative to other regions

6. Recent additions of gas-fired peakers; possible short-term overbuild

7. Adequate reserve margins

E. Texas

1. Deregulation allows utilities to retain own generation but to separate generation, transmission and distribution and retail energy provider ("REP") or broker into three separate subsidiaries or companies ("functional unbundling") and to enter into bilateral forward contracts to hedge supply and sport price risk

2. Retail price caps subject to automatic adjustment to pass through increased fuel costs

3. 18% to 26% reserve margin predicted through 2004

4. Lack of interconnection between Electric Reliability Council of Texas ("ERCOT") and other states insulates Texas from out-of-state demand and from reduction in supply from out-of-state resources, in contrast to California, which suffered both problems

5. Fuel readily available in state

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6. Regulators are industry-friendly (siting, construction, and permitting are faster and easier, and there are fewer land use and environmental controls)

F. California

1. Recent and planned significant increases in supply to address recent capacity deficit
2. Market stabilizing and utilities recovering
3. Deregulation in limbo (see above)

V. FUTURE OF DOMESTIC PROJECT FINANCE MARKET

A. *Utility Credit – Mitigants to Supply and Price Volatility Risks*

1. Added or retained owned generation
2. Added liquidity
3. Forward power purchases / long term contracts (incl. with spun-off generation affiliates) to hedge part of baseload demand
4. Regulatory approval for power cost recovery mechanisms or energy cost deferral mechanisms
5. Manage provider-of-last-resort (POLR) risk in face of supply and price volatility

B. Independent Generators

1. Independent generators face a tension between leverage and EPS growth, particularly for Gencos that are public companies.
2. Challenge: To satisfy equity markets quarter by quarter, independent generators need to show both consistent capacity growth (installed MW) and GAAP earnings growth, which becomes harder to do as markets mature, demand weakens, and increasing leverage adds to capital costs.
3. Gencos need to raise capital continuously in the face of declining share prices, lower P/E ratios, and more challenging market opportunities
4. Tradeoff between shareholder return and maintaining bond ratings

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5. Diversification benefits can outweigh structural subordination of corporate debt versus project debt; thus, one would expect to see more holding company and portfolio financing so long as corporate balance sheets can absorb the added debt.

6. Many independent generators that were spun off from utility affiliates may again be acquired by utility holding companies.

7. Trend: Go overseas to increase returns and demonstrate growth (*déjà vu* – the last significant power investments outside of the United States were made in 1990s, in the wake of our last recession)

8. Within the United States, expect…

    a. more gas-fired greenfield development, though at a slower pace than in the past few years,

    b. location-specific greenfield and brownfield development,

    c. buying old assets or other independent power companies, either to create new operating efficiencies or as part of a large trend of consolidation as companies seek to increase the size of their balance sheets, their free cash flow, and their debt capacity,

    d. increasing effectiveness or environmental performance of existing assets, and the retiring of old plants in favor of new plants even in markets that have overcapacity today, and

    e. location-specific merchant plants that are designed to capitalize on transmission system advantages or constraints, not just on fuel efficient turbines.

9. Outside the United States, expect…

    a. renewed interest by many Gencos in expanding internationally, especially in developing countries and other areas where less mature markets hold possibilities of higher returns,

    b. in the last wave of foreign investment, many companies were successful but many others did not meet their expectations or had expensive failures, causing some companies to study more carefully what worked before and to learn from their experience;

    c. continued consternation over currency and political risks, and

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d. more companies will share risks through consolidation, portfolio investments, joint ventures (using project finance techniques), and public-private partnerships. All of these trends will require the mobilization of increasingly large amounts of capital, favoring larger market players with other steady sources of cash flow.

VI. EFFECT ON FINANCING STRUCTURES – MARKET TRENDS TO WATCH

A. Merchant plants and plants with tolling arrangements increasingly have same risk profile, as the credit of many tollers (companies, often utilities, that agree both to purchase power and to provide fuel or cover fuel costs for a particular plant) deteriorates.

B. Merchant power plants may become more difficult to finance, given uncertainty about forward price curves, buyer credit, and deregulated market rules.

C. There is a trend towards shorter tenor (7 years or less) in the bank credit market, which increases refinancing risk and lowers return on equity for developers.

D. Increased coverage requirements will boost equity requirements and lower IRRs.

E. Many power markets may face short term capacity spurts and high price volatility, especially in the early transition to deregulation. This has been the pattern in other newly deregulated commodity markets.

F. There may be more portfolio or multi-asset financings and fewer stand alone, single asset project financings by larger companies with strong balance sheets, in part due to the post-Enron trend toward greater transparency in financial reporting and the desire of many CFOs and corporate treasurers to align balance sheets with corporate credit risk.

G. Fewer deals will be driven by purely accounting or tax motives.

H. Expect heightened government scrutiny and quicker intervention when markets or major market participants are in jeopardy.

I. There will be increasing demand for full and complete disclosures by company and its officers and insiders (e.g., law firms, accounting, lenders, etc.).

J. Companies that lack debt capacity, and joint ventures created to minimize risks in many large, often foreign projects, may again use more stand-alone, asset/cash-flow backed, non-recourse project financings, as it may be otherwise difficult for them to attract capital for new projects on viable terms.

K. Overall, though, expect increasing reliance on corporate balance sheets.

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