The Energy Bar Association Announces its Mid-Year Meeting

December 1, 2011
Grand Hyatt Washington
1000 H Street, N.W., Washington, D.C.
**Transformation in the Energy Industry:**  
**Electric and Gas Convergence, Business Challenges, New Technologies and the World After Fukushima**

An evolving political climate, new technologies and changing business imperatives are shifting the groundwork for the energy industry. Increasing convergence between the electric and gas industries is evident as the role of natural gas in electricity production increases, renewables struggle for new markets, and the nuclear industry grapples with its future in the wake of Fukushima. FERC continues to drive the energy industry's agenda, with its issuance of Order No. 1000, contemplating an ambitious new role for the Commission in overseeing regional and interregional processes to facilitate substantial new transmission development. In addition, major utility players have recently proposed substantial mergers suggesting that the face of the utility industry may soon undergo meaningful change. The 2011 Mid-Year Program tackles these developments, bringing together speakers from the industry, academia and government.

### PROGRAM SCHEDULE

**THURSDAY, DECEMBER 1, 2011**

<table>
<thead>
<tr>
<th>Time</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>8:00 a.m.</td>
<td>REGISTRATION</td>
</tr>
<tr>
<td>8:20 a.m.</td>
<td>WELCOME AND INTRODUCTION</td>
</tr>
<tr>
<td></td>
<td>Jane E. Rueger</td>
</tr>
<tr>
<td></td>
<td>Co-Chair, EBA Programs &amp; Meetings</td>
</tr>
<tr>
<td></td>
<td>Committee</td>
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<tr>
<td></td>
<td>White &amp; Case LLP</td>
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<tr>
<td></td>
<td>Derek A. Dyson</td>
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<td></td>
<td>President, Energy Bar Association</td>
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<tr>
<td></td>
<td>Duncan, Weinberg, Genzer &amp; Pembroke, P.C.</td>
</tr>
<tr>
<td>8:30 - 9:45 a.m.</td>
<td>KEYNOTE PANEL</td>
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<tr>
<td>9:45 - 11:00 a.m.</td>
<td>The Evolving Relationship Between the Electric and Gas Industries</td>
</tr>
</tbody>
</table>

**Moderator:** Jonathan D. Schneider  
Co-Chair, EBA Program Committee  
Stinson Morrison Hecker LLP  

**Panelists:**  
Dan Reicher  
Executive Director of the Steyer-Taylor Center for Energy Policy and Finance  
Stanford Law School  
Tom Alley  
Vice President, Generation  
Electric Power Research Institute  
John Eber  
Managing Director, Energy Investments  
JP Morgan  
David K. Owens  
Executive Vice President, Business Operations  
Edison Electric Institute  
Lisa E. Epifani  
Van Ness Feldman, P.C.  
Raymond W. Hepper  
Vice President, General Counsel and Corporate Secretary  
ISO-New England  
Colin Harper  
NiSource  
Regina Y. Speed-Bost  
Schiff Hardin LLP  
Michael T. Hunt  
Managing Director of Product Services  
Virginia Power Energy Marketing
11:00 - 11:15 a.m.  NETWORKING BREAK

11:15 a.m. - 12:30 p.m.  Transmission Planning, Cost Allocation, Incentives and Renewable Integration

With the issuance of Order No. 1000, FERC has set the electric industry off on a year-long trek to develop processes for regional transmission planning and cost allocation plans, and an 18 month journey to develop interregional processes aimed at setting the framework for developing transmission to meet reliability needs, improve market function and pave the way for the interconnection of new generating resources. Simultaneously, the Commission has embarked on a fresh consideration of incentives for transmission construction, and a rulemaking addressing protocols for the integration of renewable resources. How the lines are being drawn on rehearing and in regional discussions, whether FERC’s goals are realistic or sensible, what issues will remain for the courts and what the industry will look like when the proceedings are done will be explored by this panel.

Moderator: Carrie Bumgarner
Wright & Talisman P.C.

Panelists:
Mason Emnett
Associate Director, Office of Energy Policy and Innovation
Federal Energy Regulatory Commission

Robert E. Gramlich
American Wind Energy Association

Andrew W. Tunnell
Balch & Bingham LLP

Vincent P. Duane
PJM Interconnection, L.L.C.

12:30 p.m. - LUNCHEON AND LUNCHEON SPEAKER

Introduction: Derek A. Dyson
President, Energy Bar Association
Duncan, Weinberg, Genzer & Pembroke, P.C.

Speaker: Joseph Goffman
Senior Counsel for Air and Radiation
Environmental Protection Agency

2:00 - 3:30 p.m. CONCURRENT SESSIONS

Session A: Electric Industry Consolidation and Merger Policy

While repeal of the Public Utility Holding Company Act in 2005 did not trigger the flood of electric utility mergers some predicted, several large merger announcements over the course of the past two years suggest that the post-PUHCA wave may have started. The Federal Trade Commission and the Department of Justice revised their Horizontal Merger Guidelines, and the Federal Energy Regulatory Commission is considering revisions to its Merger Policy in light of the DOJ and FTC changes. This panel will explore the implications of PUHCA’s repeal, what animates recent merger announcements, changes to the FTC/DOJ Merger Guidelines and FERC’s associated Notice of Inquiry, and state commission responses to mergers affecting utilities in their states.

Moderator: Mark S. Hegedus
Federal Trade Commission

Panelists:
Mark J. Niefer
U.S. Department of Justice

Clifford (Mike) Naeve
Former Commissioner, Federal Energy Regulatory Commission

Skadden, Arps, Slate, Meagher & Flom LLP

Darren Bush
Professor of Antitrust Law
University of Houston

H. Russell Frisby, Jr.
Stinson Morrison Hecker LLP
Former Chairman, Maryland PSC

Session B: Economic and Regulatory Trends Transforming the Interstate Natural Gas Pipeline Industry

Policy makers are processing the implications of the domestic shale gas resources that appear to be available in the continental United States. Pipelines continue to be transferred into master limited partnerships, and the Southern Union- Energy Transfer Equity-Williams Companies merger battle may reflect larger forces that will further drive structural change in the industry. Concerns with aging infrastructure and the new safety, environmental and cyber-security regulations being overlaid on the industry’s ever-more competitive landscape contributes to this transformation. The panel will explore the impact of these developments on pipeline rates, contracting plans and associated regulatory policies.
Session A: Ethics Panel

This panel will focus on the application of the Model Rules of Professional Conduct to practice before the FERC. The panel will highlight related federal statutes and FERC regulations and how they clarify the model rules. Areas of particular focus will include: (1) truthfulness in statements to others, including the government; (2) ex parte communications; and (3) conflicts of interest that apply to government officers and employees that enter private practice.

Panelists: Sidney Rocke
Deputy Associate General Counsel, Office of General Counsel
Federal Energy Regulatory Commission
Marcos A. Araus
Attorney-Adviser, Office of General Counsel
Federal Energy Regulatory Commission

Session B: The Nuclear Industry in a Post-Fukushima World

On March 11, 2011, Japan’s Fukushima Daiichi nuclear power plant was damaged in a magnitude 9.0 earthquake and subsequent tsunami, challenging the structural integrity and safety of the plant. The ensuing problems at the plant captivated the world. The nuclear industry, which had been reenergized in recent years by the focus on clean energy and the need for low-carbon baseload power, suddenly found itself under the glaring spotlight of the 24/7 news cycle. The nuclear industry and the Nuclear Regulatory Commission (NRC) are taking a hard look at the issues identified in Japan and their implications for U.S. operating nuclear power plants and the licensing of new plants. Additionally, the President’s Blue Ribbon Commission (BRC) on America’s Nuclear Future has issued its draft report on July 29, 2011, providing recommendations for developing a safe, long-term solution to managing spent nuclear fuel and nuclear waste in the U.S.

The panel will look at the U.S. response to Fukushima and the impact the event will have on the nuclear industry, including new plant development, taking into account the important issue of spent fuel management.

Panelists: The Honorable William Magwood IV
Commissioner
U.S. Nuclear Regulatory Commission
James Scarola
Senior Vice President and Chief Nuclear Officer of Progress Energy Carolinas
Progress Energy
Stephen Maloney
Azuolas Risk Advisors
Mary Anne Sullivan
Hogan Lovells US LLP

5:30 - 7:30 p.m. CHARITABLE FOUNDATION OF THE ENERGY BAR ASSOCIATION RECEPTION

The Charitable Foundation of the Energy Bar Association will be holding its Ninth Annual Fundraising Gala - Cocktail Reception. A contribution is required (please see registration form).
KEYNOTE PANEL
Looking Through a Cloudy Crystal Ball at the Future of Power Supply Options

Energy Bar Association
Mid-Year Meeting

Tom Alley
Vice President - Generation
December 1, 2011
The story…

- Unique convergence of major challenges faces the electricity sector

- Energy-economic analyses by EPRI and others …underscores the economic value of maintaining a diverse portfolio of electricity generation technologies

- Technology diversity will be an essential “hedge” against unexpected barriers to technology development
Converging Policy Drivers

• CO$_2$ policy
• Other potential issues
  - Ash
  - Environmental impact of renewables
  - Water availability for power plant cooling
• Existing environmental policies (e.g. SO$_x$, NO$_x$)
• Renewable Portfolio Standards (RPS)/Renewable Energy Standards (RES)
The Challenge

Provide society with... while helping to transform the Power System to a cleaner, modern generation fleet, and interactive electrical grid.

Affordable

Environmentally Responsible

Reliable

Electricity
Backdrop...the Affordability Challenge

U.S. Retail Price of Electricity

Flat real electricity prices for last 40 years...
what about the next 40 years?
Assessing Technology Development...

Through a Rigorous Energy-Economic Analysis...

- View electricity sector in context of overall U.S. and global economy
- Integrate effects of expected policies (CO₂, EPA, RPS) with technology cost and development assumptions in different scenarios
- Model optimization of economic production through competition between options to invest capital, labor, electric and non-electric energy in different economic sectors.
- Allow for additional assumptions re: energy consumption behavior, public policy, etc.
Prism CO$_2$ Reductions … Technical Potential*

*Achieving all targets is very aggressive, but potentially feasible.

EIA Base Case 2009

41% reduction in 2030 from 2005 level is technically feasible using a full portfolio of technologies
EPRI Energy-Economic Analysis Approach

• Analyze spectrum of technology and policy scenarios
• Treat “regionality” of renewables
• Include…
  – Potential investments in demand-side (efficiency, transportation)
  – Effects of varying electricity demand
  – Major inter-regional electricity flows
  – Full complement of environmental regulations (EPA, RPS)
New Wind Resource Data: Capturing the Variability of Wind

- AWS Truepower 200m resolution wind data
  - Based on actual hourly 1997-2008 meteorology
  - Provides simulated output for typical turbine (80m height, 1.5 MW)

- Identified 5300+ “utility-scale” sites
  - Exclusion areas
  - 100 MW site minimum
  - Distance to grid
  - Terrain/wake effects
**2010-2011 Energy-Economic Analysis**

Preliminary Scenarios (national scale)

Optimistic Technology Development Scenario

- EE & Price Response
- Wind
- Existing / new Nuclear
- Gas
- Gas-CCS
- Coal
- Coal-CCS

Pessimistic Technology Development Scenario

- (no new nuclear or CCS)

For information only – preliminary

<table>
<thead>
<tr>
<th>Scenario</th>
<th>TWh</th>
<th>GtCO₂</th>
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<tbody>
<tr>
<td>EE &amp; Price Response</td>
<td>7000</td>
<td>2.5</td>
</tr>
<tr>
<td>AEO 2010 Ref. Case</td>
<td>6000</td>
<td>2.0</td>
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<tr>
<td>Energy Efficiency*</td>
<td>5000</td>
<td>1.5</td>
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<tr>
<td>Geo+Sol</td>
<td>4000</td>
<td>1.0</td>
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<tr>
<td>Biomass</td>
<td>3000</td>
<td>0.5</td>
</tr>
<tr>
<td>Wind</td>
<td>2000</td>
<td>0.0</td>
</tr>
<tr>
<td>Hydro+</td>
<td>1000</td>
<td>0.0</td>
</tr>
<tr>
<td>Nuclear</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Gas-CCS</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Gas</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Coal-CCS</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Coal</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Tons CO₂</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

* Includes new programs, technology, and behavioral price response

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Prism 2.0 “Test Drive” Regional Views

One size does not fit all!
Prism 2.0 ...the Big “Ah-ha’s!”

Differences matter...but it’s not that simple...

• Different regions will respond differently to a policy constraint based on...
  – Resource endowments
  – Fossil fleet
  – Demographics

• Despite regional differences and uncertain policy future...**innovation in energy R&D** makes sense for everyone and yields benefits for all

*Innovation...one certainty in an uncertain world.*
Key Takeaways

Looking ahead…a very delicate balancing act…

• Unique challenges face the electricity sector

• Great economic value in having a diverse portfolio of generation technologies

• Our collective challenge: NOT to choose between technologies, but to choose the appropriate mix.

• Decisions over the next decade will shape the electricity future of 2050
But All This Will All Take Time…

Transition...then transformation...

• Much of the technology needed to meet many of our demands is either not available or too expensive

• Some technologies will be critical to “bridging” the gap between today and a very different electricity technology mix in the future

• Disruption can come in different ways:
  – Substantially larger or smaller roles for certain technologies relative to the past
  – Unexpected technology barriers
Technology ... the essential puzzle piece...

“The best way to predict the future... is to create it.”

- Peter Drucker
For More Information

2009 Prism-MERGE
EPRI Report #1020389
www.epri.com

2010 Preliminary
Prism 2.0
www.epri.com,
“Newsroom”,
“2010 Summer Seminar”
Together…Shaping the Future of Electricity
JPMCC is a leading renewable energy tax equity investor and arranger

**JPMCC’s impact in the US renewable energy industry**

- Since 2003, J.P. Morgan has invested or arranged $7.1 billion of tax equity capital in renewable energy projects through June 2011
  - $3.4 billion of J.P. Morgan’s capital
  - $3.7 billion of co-investor capital
- J.P. Morgan’s $2.4 billion renewable energy portfolio as of June 2011 includes
  - 72 wind farms representing about 7,000 MW of capacity located in 18 different states
  - 13 solar sites including 12 PV projects and the largest solar energy project built in more than a decade (Nevada Solar One, 64 MW solar thermal facility)
- 2011 year-to-date activity:
  - $640mm funded by JPMCC in 6 transactions consisting of 14 projects
- US based properties
- Permanent financing
- The wind industry installed 5,116 MW in the U.S. in 2010

- There was 15% growth in 2010 with average annual growth for the past five years of 35%

- There were 3,360 MW of wind projects installed in 3Q 2011, up 74% from the first three quarters of 2010.

- The total U.S. installed wind capacity now stands at 43,641 MW.

Source: AWEA Third Quarter Market Report 2011
Wind has captured 35% of all new generating capacity in America since 2007

- New wind capacity represented 26% of all new capacity installed in 2010.

- Wind remained the second largest source of new installed capacity, second to natural gas at 40%.

- All new renewable capacity combined represented nearly 33% in 2010.

- Over the past 4 years combined, wind represented 35% of all new generating capacity installed.

Data Source: AWEA, EIA, SEIA, SNL
U.S. Top 20 Wind Power Capacity Owners in 2010

Ownership is on a net basis, so if two owners have a half share of a 100-MW wind farm, each company is credited with 50 MW. Ownership does not include structural investors, which may have a share of equity.

## Top 20 Investor-Owned Utilities With Wind Capacity on System

<table>
<thead>
<tr>
<th>Power Company</th>
<th>Under Contract (MW) (PPA)</th>
<th>Utility-Owned (MW)**</th>
<th>Total (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Xcel Energy</td>
<td>3,130</td>
<td>328</td>
<td>3,458</td>
</tr>
<tr>
<td>MidAmerican Energy (including PacifiCorp)*</td>
<td>813</td>
<td>2,316</td>
<td>3,129</td>
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<tr>
<td>Southern California Edison</td>
<td>2,058</td>
<td>0</td>
<td>2,058</td>
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<tr>
<td>Pacific Gas &amp; Electric</td>
<td>1,395</td>
<td>0</td>
<td>1,395</td>
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<tr>
<td>American Electric Power</td>
<td>1,395</td>
<td>0</td>
<td>1,395</td>
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<tr>
<td>Luminant Energy (formerly TXU)</td>
<td>913</td>
<td>0</td>
<td>913</td>
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<tr>
<td>Alliant Energy</td>
<td>378</td>
<td>267</td>
<td>645</td>
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<tr>
<td>Portland General Electric</td>
<td>100</td>
<td>450</td>
<td>550</td>
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<tr>
<td>Puget Sound Energy*</td>
<td>50</td>
<td>429</td>
<td>479</td>
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<tr>
<td>Oklahoma Gas &amp; Electric</td>
<td>203</td>
<td>221</td>
<td>424</td>
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<tr>
<td>First Energy</td>
<td>376</td>
<td>0</td>
<td>376</td>
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<tr>
<td>San Diego Gas &amp; Electric</td>
<td>342</td>
<td>0</td>
<td>342</td>
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<tr>
<td>Westar</td>
<td>146</td>
<td>149</td>
<td>295</td>
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<tr>
<td>Idaho Power</td>
<td>269</td>
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<tr>
<td>We Energies</td>
<td>76</td>
<td>147</td>
<td>222</td>
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<tr>
<td>Public Service Company of New Mexico</td>
<td>204</td>
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<tr>
<td>Arizona Public Service</td>
<td>190</td>
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<tr>
<td>Wisconsin Public Service</td>
<td>76</td>
<td>109</td>
<td>187</td>
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<tr>
<td>Otter Tail Power</td>
<td>45</td>
<td>138</td>
<td>183</td>
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<tr>
<td>Northwestern Energy</td>
<td>173</td>
<td>0</td>
<td>173</td>
</tr>
</tbody>
</table>

## Power Purchase Agreements: Third Quarter

<table>
<thead>
<tr>
<th>Offtaker</th>
<th>Project Owner</th>
<th>Contract Amount</th>
<th>Project Name</th>
<th>State</th>
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</thead>
<tbody>
<tr>
<td>Alabama Power Company</td>
<td>TradeWind Energy</td>
<td>202 MW; 20 years</td>
<td>Chisolm View</td>
<td>OK</td>
</tr>
<tr>
<td>Associated Electric Cooperative</td>
<td>Wind Capital Group</td>
<td>150.4 MW</td>
<td>Osage County</td>
<td>OK</td>
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<tr>
<td>Austin Energy</td>
<td>Duke Energy</td>
<td>201.6 MW; 25 years</td>
<td>Los Vientos II</td>
<td>TX</td>
</tr>
<tr>
<td>Austin Energy</td>
<td>Iberdrola Renewables</td>
<td>200 MW; 25 years</td>
<td>Penascal III</td>
<td>TX</td>
</tr>
<tr>
<td>Austin Energy</td>
<td>MAP Royalty</td>
<td>91 MW; 25 years</td>
<td>White Tail</td>
<td>TX</td>
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<tr>
<td>CPS Energy</td>
<td>Duke Energy</td>
<td>200.1 MW; 25 years</td>
<td>Los Vientos I</td>
<td>TX</td>
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<tr>
<td>Detroit Edison</td>
<td>NextEra Energy Resources</td>
<td>120 MW; 20 years</td>
<td>Tuscola Bay</td>
<td>MI</td>
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<tr>
<td>Old Dominion Electric Cooperative</td>
<td>BP Wind Energy</td>
<td>75 MW; 20 years</td>
<td>Mehoopany</td>
<td>PA</td>
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<tr>
<td>Pacific Gas &amp; Electric Co.</td>
<td>enXco</td>
<td>100 MW; 25 years</td>
<td>Shiloh IV</td>
<td>CA</td>
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<tr>
<td>Pacific Gas &amp; Electric Co.</td>
<td>NextEra Energy Resources</td>
<td>163 MW</td>
<td>North Sky River</td>
<td>CA</td>
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<tr>
<td>Southern Maryland Electric Cooperative</td>
<td>BP Wind Energy</td>
<td>30 MW; 20 years</td>
<td>Mehoopany</td>
<td>PA</td>
</tr>
<tr>
<td>Sunflower Electric Power</td>
<td>Infinity Wind</td>
<td>104 MW; 20 years</td>
<td>Shooting Star</td>
<td>KS</td>
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<tr>
<td>Tennessee Valley Authority</td>
<td>EDP Renewables North America</td>
<td>101 MW; 19 years</td>
<td>Lost Lakes*</td>
<td>IA</td>
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<tr>
<td>Xcel Energy</td>
<td>Geronimo Wind Energy</td>
<td>200 MW</td>
<td>Prairie Rose</td>
<td>MN</td>
</tr>
</tbody>
</table>

* Project has been operational since 2009

Source: AWEA Third Quarter 2011 Market Report, Members Only Version
With 400 facilities, wind is one of the fastest-growing sources of U.S. manufacturing jobs.

At the end of 2010, there were over 400 manufacturing facilities online making wind-related products.

The online facilities span 43 states.

Increase in Wind Turbine Productivity

Technology has continued to improved with taller towers, larger rotors, increased turbines availability, and better siting technology to achieve increased capacity factors.

This improved performance translates into a turbine with a nameplate capacity 7 times larger than a typical turbine in 1990 that can produce 15 times more electricity.

Actual Price of Wind Projects, 2007-2010

Source: DOE Wind Technologies Market Report, 2010
National Policies

Production Tax Credit (PTC): *Online by December 31, 2012*
- 2.2 cents per kWh over 10 years in form of a tax credit

Alternatives to the PTC:

*Investment Tax Credit (ITC): *Online by December 31, 2012*
- 30% of upfront investment in form of a tax credit

- 30% of upfront investment alternative to the ITC in form of cash
History of Boom & Bust Environment

# Wind Integration Costs are Modest

<table>
<thead>
<tr>
<th>Date</th>
<th>Study</th>
<th>Wind Capacity Penetration (%)</th>
<th>Regulation Cost ($/MWh)</th>
<th>Load Following Cost ($/MWh)</th>
<th>Unit Commitment Cost ($/MWh)</th>
<th>Gas Supply Cost ($/MWh)</th>
<th>Total Operating Cost Impact ($/MWh)</th>
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<tbody>
<tr>
<td>May '03</td>
<td>Xcel-UWIG</td>
<td>3.5</td>
<td>0</td>
<td>0.41</td>
<td>1.44</td>
<td>na</td>
<td>1.85</td>
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<tr>
<td>Sep '04</td>
<td>Xcel-MNDOC</td>
<td>15</td>
<td>0.23</td>
<td>na</td>
<td>4.37</td>
<td>na</td>
<td>4.60</td>
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<tr>
<td>June '06</td>
<td>CA RPS</td>
<td>4</td>
<td>0.45*</td>
<td>trace</td>
<td>na</td>
<td>na</td>
<td>0.45</td>
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<tr>
<td>Feb '07</td>
<td>GE/Pier/CAIAP</td>
<td>20</td>
<td>0-0.69</td>
<td>trace</td>
<td>na***</td>
<td>na</td>
<td>0-0.69***</td>
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<tr>
<td>June '03</td>
<td>We Energies</td>
<td>4</td>
<td>1.12</td>
<td>0.09</td>
<td>0.69</td>
<td>na</td>
<td>1.90</td>
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<tr>
<td>June '03</td>
<td>We Energies</td>
<td>29</td>
<td>1.02</td>
<td>0.15</td>
<td>1.75</td>
<td>na</td>
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<td>2005</td>
<td>PacifiCorp</td>
<td>20</td>
<td>0</td>
<td>1.6</td>
<td>3.0</td>
<td>na</td>
<td>4.60</td>
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<tr>
<td>April '06</td>
<td>Xcel-PSCo</td>
<td>10</td>
<td>0.20</td>
<td>na</td>
<td>2.26</td>
<td>1.26</td>
<td>3.72</td>
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<td>April '06</td>
<td>Xcel-PSCo</td>
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<td>na</td>
<td>3.32</td>
<td>1.45</td>
<td>4.97</td>
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<td>Dec '08</td>
<td>Xcel-PSCo</td>
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<td>0</td>
<td>3.95</td>
<td>1.18</td>
<td>**</td>
<td>5.13-6.30***</td>
</tr>
<tr>
<td>Dec '06</td>
<td>MN 20%</td>
<td>31**</td>
<td>3.75</td>
<td>2.65</td>
<td>1.06</td>
<td>na</td>
<td>4.41**</td>
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<tr>
<td>Jul '07</td>
<td>APS</td>
<td>14.8</td>
<td>0.37</td>
<td>2.65</td>
<td>1.06</td>
<td>na</td>
<td>4.08</td>
</tr>
</tbody>
</table>

Source: NREL
Key Challenges and Opportunities for the Electric Industry

David K. Owens
Executive Vice President
Edison Electric Institute

Energy Bar Association Mid-Year Meeting
December 1, 2011
Washington, DC
The U.S. Economy in 2012

- Slow to moderate GDP Growth (2.0% - 2.6% at best)
- Little change in unemployment rate (8.8% - 9.4%)
- Interest rates remain low
- Inflation held in check (CPI ≈ 2%)
- No quick turn-around in the housing market
  - Home prices lower in 2012, major drag on the economy
  - New construction and existing home sales slow to rise
  - 30% of homeowners underwater
- Little or no growth in energy sales
Utility industry has embarked on a major investment cycle, driven by the need to address:

- Generation, Transmission, and Distribution to ensure reliability
- Energy Efficiency and deploying new technologies (SG, renewables)
- Significant Environmental CAPEX

Increasing concerns about the Environment has Changed our Power Supply Mix

- Short term: Rely on Energy Efficiency, Renewables, and Natural Gas
- Medium-term: Targets should be harmonized with the development and commercial deployment of advanced technologies and measures (e.g., Nuclear Energy, Advanced Coal Technologies with Carbon Capture and Storage, Plug-in Electric Vehicles, and Smart Grid)

We are no longer a declining cost industry
Changing Electric Utility Landscape (2)

- An Increasing Amount of Rate Cases to Pay for Investments
- Our Workforce is Aging and our Children are Less Educated
- The Utility Role for Driving New Technology has become increasingly complicated
  - Current combination of low economic growth, flat electricity demand growth, deficit concerns and sustained high unemployment is slowing down the deployment of smart technologies including Smart Grid
- New Congress with vastly different priorities
Cyber Security Legislation Outlook

- Bipartisan support for cyber security legislation – despite gridlocked Congress
- President Obama’s proposal in May provided additional guidance and push for Congress to act
- Challenges include navigating 14 committees in House and Senate with jurisdiction
- Strong cyber security legislation should:
  - Limit scope of any new federal emergency to imminent threats against truly critical assets
  - Ensure emergency orders come from only one government entity
  - Include all critical infrastructure sectors in a cyber security regime
  - Encourage more information-sharing between gov’t and industry
Uncertainty Looms!!
### Industry Capital Expenditures

#### U.S. Shareholder-Owned Electric Utilities

<table>
<thead>
<tr>
<th>Year</th>
<th>Expenditures ($ Billions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>43.0</td>
</tr>
<tr>
<td>2004</td>
<td>41.1</td>
</tr>
<tr>
<td>2005</td>
<td>48.4</td>
</tr>
<tr>
<td>2006</td>
<td>59.9</td>
</tr>
<tr>
<td>2007</td>
<td>74.1</td>
</tr>
<tr>
<td>2008</td>
<td>83.0</td>
</tr>
<tr>
<td>2009</td>
<td>77.8</td>
</tr>
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<td>2010p</td>
<td>82.8</td>
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<tr>
<td>2011p</td>
<td>83.3</td>
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<tr>
<td>2012p</td>
<td>85.0</td>
</tr>
<tr>
<td>2013p</td>
<td>82.6</td>
</tr>
</tbody>
</table>

**Source:** SNL Financial, company reports and EEI Finance Dept.

**Note:** Starting in 2008, the universe of companies drops from 69 to 63, removing six companies that did not file Form 10-K with the SEC.
By 2030, the electric utility industry will need to make infrastructure investments of $1,830 Billion

This level of investment is nearly triple the US Shareholder–Owned Electric Utilities’ current net plant value of roughly $650 billion (12/3/10 = $737 B)

Source: Transforming America’s Power Industry, The Brattle Group, November 2008
Electricity Game Changers

Public Policy
Environmental

Energy Source
Shale Gas

Technology
Smart Grid

Japan Nuclear Disaster?
Divergent Forces

- Environmental Regulations
- Congress/States/FERC
- Sales/Economic Recovery
- Public
- Technology
- Markets
Power Plants Reduce Emissions Despite Increasing Electricity Demand

Graph showing the trend of emissions and electricity demand from 1990 to 2010:
- Real GDP increased by 65%
- Electricity Use increased by 38%
- SO₂ Emissions decreased by 67%
- NOₓ Emissions decreased by 68%

Index 1990 = 100

1990 represents the base year. Graph depicts increases or decreases from the base year.

Sources: U.S. Department of Energy, Energy Information Administration (EIA), U.S. Environmental Protection Agency (EPA), and U.S. Bureau of Economic Analysis.

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Power Sector Objectives

- Minimize economic impacts to consumers
- Continue environmental improvements
- Maintain system reliability
- Maintain fuel diversity options
- Develop and deploy new technologies
- Obtain access to capital and cost recovery
- Negotiate myriad political landscapes
U.S. Shale – A Game Changer?
Gas Production Potential

Source: Tristone Capital, Devon Energy
Natural Gas Trends

Challenges Ahead

- Regulatory
  - Hydraulic fracturing

- Public opposition
  - Drinking water contamination concerns and waste water / surface contamination

- GHG reduction implications

- Price level and volatility

- Pipeline access / availability
Why Do We Need A Smarter Grid? (Grid Modernization)

Utilities are facing major challenges:
- Infrastructure investment needs--$1.5-2 Trillion
- Climate change other environmental issues
- Energy independence
- Cyber-security

A smarter grid will enable utilities to:
- Empower customers to control and optimize their energy usage
- Rely on greater amounts of distributed generation—wind, solar, etc.
- Use electricity as a fuel for vehicles
- Enhance the reliability and efficiency of the power grid
- Provide the framework and foundation for future economic growth
Smart Meter Platform and Home Area Network Technologies will take EE and DR to New Levels

...Giving customers the tools and the know-how to be smarter energy consumers

HAN communication

SmartMeter communication
A New Kind of Utility/Customer Engagement

- Use of advanced customer service channels to deliver customer benefits, choice and control
- Shift from reactive issue resolution to proactive information transfer
- Information push versus pull customer service model
There is tremendous and growing pushback from customers and regulators to the smart meter. It focuses on:

- Accuracy of meters
- Health concerns: Radio Frequency Exposure
- Who decides whether a meter should be installed?
- Cost of installation
- Access to information: privacy intrusion
- Impact “at risk” customers
- Dynamic pricing
- Customers are not seeing immediate benefits
The United States is facing a critical shortage of trained professionals to maintain the existing electric power system and to design, build, and operate the future system.

This shortage has potential to jeopardize:

- Reliability and cost effectiveness of current system
- Ability to transition to a low carbon electricity system
Twin Challenges (Opportunities?) Facing the Electric Power Sector

- **Near-Term Retirements**
  - 30 to 40 percent, or roughly 150,000 of the 400,000 workers employed in the electric power sector are eligible for retirement or will leave the sector in the next 5 years.
  - Replacing these workers is imperative to maintaining the integrity of the current system.

- **Long-Term Transition to a Low-Carbon Economy**
  - De-carbonizing the electric power sector will require roughly 150,000 workers to design, construct, and operate the next generation of electric sector infrastructure.

Combined, these challenges represent replacement of 80% of the current electric power sector work force--300,000 jobs.
What is the Industry Doing?

- Established a Center for Workforce Development (CEWD)
  - Created partnership at the national and state level that pulls together educators, government agencies and the industry to leverage resources to fill workforce gaps
  - CEWD has facilitated the creation of 28 state energy workforce consortia tailored to meet state needs.

- Established Troops to Energy Jobs
  - To accelerate training and employment of military veterans for key energy positions
New Approaches to Regulating Utilities in Changing Times
A Paradigm Shift

THEN... large periodic projects to support strong load growth required infrequent, but major, rate cases

NOW... Ongoing investment well above depreciation and slower sales growth requires ongoing rate increases
Overview of the Problem

Energy Growth Per Customer → Realized Return → Credit Worthiness

Regulatory Lag

Capital Investment

Cost of Capital
Overview of the Solution: Electric Ratemaking

- Innovative regulatory policies and mechanisms:
  - Future test year
  - Tracker/rider mechanisms
  - CWIP in rate base
  - Formula rate plans
  - Decoupling
  - Performance-based rate plans (rate caps, revenue caps)

- Strategies to mitigate rate shock, preserve credit worthiness, incent efficient management
New rate regulatory approaches essential to financing needed infrastructure in today's environment and protecting consumers.

There is no standard framework, but there is a fairly standard toolkit of component policies.

Rebalancing risk does not mean shifting all the risk to consumers.
Energy is the foundation of America’s strength and competitiveness.

Energy policy must ensure that consumers and businesses have access to reliable and affordable energy.

The utility business model is changing; we are getting “greener”, and we need to learn how to do it profitably.

The education pipeline is leaking. We must excite our young people to pursue Science, Technology, Engineering, and Mathematics (STEM); they are our future for new technology development and American’s competitiveness.
NOTES
The Evolving Relationship Between the Electric and Gas Industries
The New England Perspective: Gas/Electric Interdependence

Raymond W. Hepper
Vice President, General Counsel, and Corporate Secretary
About ISO New England & Regional Grid

ISO New England

- Private not-for-profit
- Regulated by FERC
- Created in 1997
- Independent of companies doing business in the markets
- Located in western Massachusetts

Regional Power Grid

- Population 14 million
- 6.5 million residents/businesses
- > 350 generators
- > 5,000 demand assets
- > 8,000 miles high-voltage transmission
- 13 interconnections
- ~ 32,000 MW of total supply
- ~ 2,800 MW of demand resources
- All-time peak demand of 28,130 MW
Outline of Presentation

• New England is increasingly dependent on gas-fired generation
• There’s a significant amount of at-risk oil-fired and nuclear generation
  – But this generation can play an important role (e.g., July 22)
• Gas supply may be limited in winter (e.g., Cold Snap)
• A review of these issues is underway
  – Includes a regional Strategic Planning Initiative to address key risks, including gas dependence
  – First step is a study of gas supplies to New England through 2020
• More information
  – Appendix A: Background on New England resource mix
  – Appendix B: Concerns about gas dependency
  – Appendix C: Overview of natural gas supply to New England
  – Appendix D: Improved gas/electric coordination
New England’s Resource Mix

Capacity development has shifted from oil and nuclear power to natural gas and demand resources

* The reduction in capacity between 1990 and 2000 is largely due to the shutdown of more than 2,300 MW of nuclear capacity in the 1990s.
Dramatic Shift in Energy Production

From Oil to Natural Gas

Percent of total generation

- 1990:
  - Hydro & other renewables: 36%
  - Pumped storage: 6%
  - Coal: 16%
  - Nuclear: 2%
  - Oil: 7%
  - Natural gas: <1%

- 2000:
  - Hydro & other renewables: 31%
  - Pumped storage: 15%
  - Coal: 18%
  - Nuclear: 2%
  - Oil: 13%
  - Natural gas: 0.4%

- 2010:
  - Hydro & other renewables: 30%
  - Pumped storage: 11%
  - Coal: 12%
  - Nuclear: 1%
  - Oil: 12%
  - Natural gas: <1%
Generation at Peak, July 22, 2011 (26,166 MW)

Oil units provided much needed energy

- Natural Gas: 12,577 MW (48%)
- Nuclear: 4,608 MW (18%)
- Oil: 3,611 MW (14%)
- Coal: 2,383 MW (9%)
- Hydro (Pump Storage): 1,148 MW (4%)
- Other Renewables, Wind: 992 MW (4%)
- Hydro (Other): 847 MW (3%)

Total: 26,166 MW
The January 2004 Cold Snap

• Severe winter weather blanketed the greater northeast U.S. and Canada from January 14–16, 2004
  – January 2004 was the coldest January in Boston since 1888
  – Short notice of gas-fired generation outages
    • Unable to start oil-fired generation due to long start-up times
  – Almost 9,000 MW of regional capacity experienced some type of outage or reduction; some gas units sold their gas supplies
    • Total Forced Outages = 7,568 MW (Gas Units = 6,200 MW)
    • Total Reductions = 1,411 MW (Gas Units = 850 MW)
    • Total Capacity Out of Service = 8,979 MW (Gas Units 7,050 MW)
  – ISO-NE implemented Emergency Operating Procedures
    • Regional substations were manned for possible rolling blackouts
    • Public advisories were sent to conserve both electricity and natural gas
Gas Study

- ISO-NE has undertaken a “Strategic Planning Initiative” with stakeholders to address a number of key risks, including gas dependency.
- As part of this Initiative, ISO-NE is studying the amount of natural gas supply available to satisfy New England’s gas-fired power generation through 2020.
- Preliminary results show that regional gas supply capability is inadequate to satisfy New England power sector gas demands on a winter peak day over the next decade, barring additional expansion of supply capability.
  - In the event that retirements occur and are replaced with additional gas generation, the deficits increase.
- Outages of certain pipes, LNG facilities or large electric contingency on a winter day could cause dire results.
  - Loss of these assets during the summer peak also significantly tightens the market, suggesting that localized constraints may materialize.
Issues to Be Considered

- Through the Strategic Planning Initiative, potential solutions to gas dependence have been identified but not fully vetted
- They include:
  - Requiring firm gas capacity for generators
    - But does it solve the problem and at what cost?
  - Building more pipe
    - But at what cost to electric and LDC customers and with what environmental impacts?
  - Building more LNG/gas storage
    - But can it be sited and at what cost?
  - Requiring generators to burn dual fuels
    - But can permits be obtained to burn other fuels, can we require storage of fuel, and (again!) at what cost?
  - Better coordination between the gas and electric markets
    - Coordination of gas pipeline and LDC maintenance scheduling
    - Timing of gas and electric days (see next slide)
Issues to Be Considered: Natural Gas Day Versus Electric Day in New England

**GAS**

- **12:30** Gas DA Market Closes
- **17:45** Intra-day Gas Closes
- **12:30** Daily Gas (Initial) Nominations Deadline
- **17:30** Daily Gas Confirmation to Shippers
- **19:00** Evening Gas (Adjustment) Nomination Deadline
- **22:00** Evening Gas Confirmation to Shippers
- **10:00** Nomination Effective Time (Delivery): Both Daily and Evening Nominations
- **11:00** Intra-day 1 Gas Nomination Deadline
- **17:30** Daily Gas Confirmation to Shippers
- **18:00** Intra-day 2 (Adjustment) Gas Nomination Deadline
- **22:00** Intra-day 2 Gas Confirmation to Shippers

**Power Operating Day**

- **12:00** DAM Bid and Offer Period Closes
- **16:00** ISO Posts DAM Results: Supply & Demand Interfaces & ETs
- **18:00** Real-time bidding period closes: Re-offers & Self-scheduled adjustments
- **18:00 – 24:00** Reserve adequacy analysis
- **18:00 – 24:00** Update current operating plan
- **18:00 – 24:00** System dispatch on 5 min basis

**Power Operating Day**

- **16:00** RT Bidding Period Opens: Re-offers & Self-scheduled adjustments

**GAS Operating Day**

- **12:30** Gas DA Market Closes
- **17:45** Intra-day Gas Closes
- **10:00** Nomination Effective Time (Delivery): Both Daily and Evening Nominations
- **11:00** Intra-day 1 Gas Nomination Deadline
- **15:00** Intra-day 1 Gas Effective Time (Delivery)
- **18:00** Intra-day 2 (Adjustment) Gas Nomination Deadline
- **22:00** Intra-day 2 Gas Confirmation to Shippers

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- **22:00** Intra-day 2 Gas Confirmation to Shippers
Appendix A: Background on New England Resource Mix
Proposed Projects by Fuel Type
Almost 8,000 MW in ISO-NE Queue; Natural Gas & Wind are the Dominant Fuels

MW Renewables, February 2011 Queue by Fuel Type

- Natural Gas, 3,357 MW, 42%
- Wind, 2,836 MW, 36%
- Hydro (w/Pump Storage), 1,133 MW, 14%
- Biomass, 431 MW, 5%
- Coal, 44 MW, 1%
- Oil, 42 MW, 1%
- Nuclear, 42 MW, 1%
- Landfill Gas, 34 MW, 0%
Region’s Fuel Mix by In-Service Date

Vast majority of regional portfolio is comprised of older oil, coal and nuclear and new natural gas

| Fuel Type         | In-Service Date | Assets | MW   | In-Service Date | Assets | MW   | In-Service Date | Assets | MW   | In-Service Date | Assets | MW   | In-Service Date | Assets | MW   | In-Service Date | Assets | MW   | In-Service Date | Assets | MW   | %       | Total | MW % |
|-------------------|-----------------|--------|------|-----------------|--------|------|-----------------|--------|------|-----------------|--------|------|-----------------|--------|------|-----------------|--------|------|---------|-------|------|
| Gas               | 5               | 72     |      | 1               | 94     |      | 12              | 1,606  |      | 20              | 3,550  |      | 38              | 8,308  |      | 13,631          |        |      | 42.5   |       |      |
| Oil               | 3               | 10     |      | 60              | 2,328  |      | 25              | 3,984  |      | 11              | 140    |      | 27              | 597    |      | 7,112            |        |      | 22.2   |       |      |
| Nuclear           | 0               | 0      |      | 0               | 0      |      | 5               | 4,629  |      | 0               | 0      |      | 0               | 0      |      | 4,629            |        |      | 14.5   |       |      |
| Coal              | 0               | 0      |      | 13              | 2,480  |      | 2               | 184    |      | 0               | 0      |      | 0               | 0      |      | 2,664            |        |      | 8.3    |       |      |
| Pumped storage    | 1               | 29     |      | 0               | 0      |      | 6               | 1,649  |      | 0               | 0      |      | 0               | 0      |      | 1,678            |        |      | 5.2    |       |      |
| Hydro             | 68              | 695    |      | 8               | 324    |      | 161             | 195    |      | 32              | 8      |      | 34              | 118    |      | 1,341            |        |      | 4.2    |       |      |
| Misc.             | 0               | 0      |      | 1               | 43     |      | 33              | 625    |      | 28              | 206    |      | 96              | 108    |      | 982              |        |      | 3.1    |       |      |
| Totals            | 77              | 807    |      | 83              | 5,321  |      | 244             | 12,873 |      | 91              | 3,905  |      | 195             | 9,132  |      | 32,037           |        |      | 100.0  |       |      |
| % of Total MW     | 2.5%            |        |      | 16.6%           |        |      | 40.2%           |        |      | 12.2%           |        |      | 28.5%           |        |      |                   |       |      |

Note: The section marked with a blue circle indicates the significant figures, while the red circle highlights the older assets.
EPA Rulemakings
May impact up to 5,500 MW of oil generation and 1,400 MW of coal generation in New England

• Power Plant Mercury and Air Toxics Standards
  – Clean Air Act § 112(d)

• Clean Water Act
  – § 316(b) Cooling Water Intake Structures
  – § 304 Waste Water

• Particulate Matter (PM) National Ambient Air Quality Standards
  – Clean Air Act § 109(d)

• Greenhouse Gas Reporting Requirement
  – Clean Air Act § 111(b)

Rules may impact old fossil-fuel units that do not already have pollution controls
Nuclear Relicensing Is an Issue

• The future of Vermont Yankee is uncertain given challenges by the state of Vermont to continued operation of the station
  – Vermont Yankee could cease operation as early as March 2012
• Pilgrim is also awaiting re-licensing from the Nuclear Regulatory Commission due in 2012
• These potential retirements would have a significant impact
  – The region’s five nuclear power plants provide about 30% of the region’s electric energy
  – Loss of Vermont Yankee and Pilgrim will further increase our reliance on natural gas for power production
  – Each of these stations provides reliability support to the power system
Appendix B: Concerns About Gas Dependency
Difficulty in Compensating for Insufficient Gas

• When the regional gas sector experiences contingencies, New England’s gas-fired fleet is subject to curtailments
  – Because these contingencies occur in real-time, with usually no foresight, ISO-NE does not have the option to dispatch long-lead time units to mitigate the effects from unforeseen gas sector contingencies
  – The majority of regional gas-fired generators do not have dual-fuel capability and operate on an interruptible gas transportation
  – As indicated by the examples of operational issues in this presentation, experience indicates that the region needs fuel diversity and/or additional certainty with regard to gas supply for gas-fired generators
September 2, 2010

- New England experienced loss of two gas-fired units totaling approximately 1,400 MW
- Eastern Interconnection inertial response increased NY-NE interface flow from 1,400 MW to over 2,600 MW
  - Equal to approximately 90% of the loss of source
- Interchange schedules with neighboring control areas were not restored to normal within the required 15 minutes
Winter 2011

• ISO-NE implemented *Cold Weather Operations Procedures* for January 23rd and 24th, 2011
  – Regional temperatures were very cold but wind speeds were low, which would limit energy contributions from regional wind resources
• Natural gas prices spiked in New England
• There were potential natural gas pipeline curtailments
• ISO-NE proactively committed a number of older oil-fired generators, resulting in significant out-of-merit “uplift” costs
• Major generators had weather-related operational problems
• ISO-NE cancelled all transmission work that may have impacted sub-regional transfers and generator availability
Appendix C: Overview of Natural Gas Supply to New England
New England Gas Pipeline Capacity

- The majority of New England’s gas supplies are met by the six (6) interstate pipelines that serve the region:

<table>
<thead>
<tr>
<th>Pipeline System</th>
<th>Winter 2011/12 Capacity (MMcf/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Tennessee Gas Pipeline (TGP)</td>
<td>1,261</td>
</tr>
<tr>
<td>2. Algonquin Gas Transmission (AGT)</td>
<td>1,087</td>
</tr>
<tr>
<td>3. Maritimes and Northeast Pipeline (M&amp;N)</td>
<td>833</td>
</tr>
<tr>
<td>4. Iroquois Gas Transmission (IGT)</td>
<td>370</td>
</tr>
<tr>
<td>5. Portland Natural Gas Transmission (PNGTS)</td>
<td>292</td>
</tr>
<tr>
<td>6. Granite State Gas Transmission (GSGT)</td>
<td>119</td>
</tr>
</tbody>
</table>

- With the exception of Granite State, all of these pipelines provide gas transport from outside of New England into the region.
  - Granite State Gas Transmission receives all of its gas supplies from interconnects from other pipelines within New England, so its capacity is not considered as part of the region’s total supply capability.

- Two of the pipelines have planned capacity expansions.
  - Tennessee’s Northeast Supply Diversification projects add 130 MMcf/d in 2012.
  - Algonquin’s AIM Project adds 350 MMcf/d in 2014.
Natural Gas Facilities in New England

• Two Land-Based LNG Import Terminals
  – DistriGas LNG – Everett, MA – GDF Suez Gas NA
  – Canaport LNG – Saint John, New Brunswick – Repsol/Irving Oil

• Two Deepwater LNG Ports
  – Northeast Gateway – Excellerate Energy
  – Neptune LNG – Suez LNG Gas NA

• No underground storage within New England
  – Closest underground storage is in New York / Pennsylvania
    • Stagecoach Storage in NY / Leidy Storage in PA

• Above-ground gas storage is LDC LNG
  – 45 satellite LNG tanks in 5 states
Appendix D: Improved Electric/Gas Coordination
Electric/Gas Operations Committee

• ISO-NE and the Northeast Gas Association have formed the Electric/Gas Operations Committee (EGOC)
• The EGOC is responsible for:
  – Cross-training of electric and gas system operators
  – Establishing emergency communications protocols and procedures
  – Assessing and addressing system restoration issues
  – Assessing coordination of electric and gas system maintenance requirements
  – Addressing other common issues
• The list of current EGOC members includes over 50 members, with staff from ISO-NE, NYISO, PJM, NERC, NPCC, and many representatives from the regional natural gas industry (regional pipelines, gas LDCs, LNG, etc.)
Responses to the Cold Snap – ISO-NE
Cold Weather Operating Procedure

• After the January 2004 Cold Snap, ISO-NE developed Appendix H of Market Rule #1 – Operations During Cold Weather Conditions
  – Defines three stages of severity (Watch / Warning / Event)
  – **Cold Weather Watch**
    • Notification of severe weather approaching the region
    • Increased electric & gas communications
    • Cancellation of generation and transmission outages
  – **Cold Weather Warning**
    • Same measures as Cold Weather Watch
    • Requests for voluntary fuel switching
  – **Cold Weather Event**
    • Same measures as Watch & Warning
    • Realignment of the electric market timelines to maximize gas supply procurement and transportation scheduling

- After Hurricanes Katrina and Rita in 2005, ISO-NE developed Operating Procedure No. 21 – Actions During an Energy Emergency (OP21)
  - Energy emergencies may occur as a result of sustained national or regional shortages in fuel availability or deliverability to New England’s generating resources
  - Shortages of fuel may include: severe drought, interruption to availability or transportation of natural gas, liquefied natural gas, oil, or coal
  - Allows for the collection of fuel availability information from Market Participants to support the determination of energy adequacy
  - ISO-NE may commit, schedule, and dispatch the system to preserve stored fuel resources in the region to minimize the loss of regional operable capacity
FERC Order No. 698

- FERC issued Order No. 698 in 2007 requiring improved communications between the natural gas and electric industries:
  - Triggered several new/revised NAESB Business Practice Standards from the Wholesale Electric & Gas Quadrants (WEQ & WGQ)
    - ISOs, RTOs, independent transmission operators, and power plant operators must subscribe to natural gas pipeline Electronic Bulletin Boards to receive Critical Notices and Planned Maintenance Outages
    - ISOs, RTOs, independent transmission operators, and power plant operators are required to establish communication procedures with regional natural gas pipelines
FERC No. Order 698 - cont’d

- Other new/revised NAESB Business Practice Standards from WEQ & WGQ:
  
  • Required direct-connect gas-fired generation to submit daily volumes and forecasts of projected hourly fuel burns when requested
  
  • Allowed ISOs/RTOs to collect confidential natural gas supply and transportation arrangements from their gas-fired generators
  
  • Required ISOs, RTOs and natural gas pipelines to file Statements of Compliance with the communication requirements by November 1, 2007
    
    - The Electric/Gas Operations Committee approved the Electric/Gas Operations Communications Protocol on September 27, 2007
    
    - ISO-NE filed its Statement of Compliance with FERC Order 698 on November 1, 2007
"The Evolving Relationship Between the Electric and Gas Industries"

Energy Bar Association
Washington, DC
December 1, 2011

W. Colin Harper
Sr. Vice President – Corporate Development
NGT&S Assets

15,500 Pipeline Miles
Annual Deliveries: 1.4 Tcf
Peak Day Deliveries: 7.7 Bcf
Serving 40 Markets
Operations in 16 states

37 Storage Fields
Capacity: 615 Bcf
Daily Delivery: 4.8 Bcf
Working Gas: 280 Bcf

106 Compressor Stations
Horsepower: 1,100,000

NiSource Gas Transmission & Storage
• Approximately 11,100 miles of pipeline

• Annually delivers about 1 Tcf to 72 LDCs and several hundred gas end-users

• Peak day deliveries – 7.4 Bcf (4.8 Bcf from storage)

• 37 storage fields in four states
  – 650 Bcf total operating capacity
  – 280 Bcf working capacity

• 91 compressor stations with more than 500,000 horsepower
Columbia Gulf Transmission

- Operations in Louisiana, Mississippi, Tennessee, and Kentucky
- More than 3,000 miles of pipeline
- 11 compressor stations with about 400,000 horsepower
- Transports natural gas primarily into Columbia Gas Transmission’s system
- Gas-fired generation market of ~ .6 Bcf/d
NGT&S Power Markets

- 12 existing power generators directly connected to NGT&S assets
- Another 10 generators currently looking to site incremental generation assets on the system
- Approximately .7 Bcf/d of power load on CGT
- Approximately 1.5 Bcf/d of power load on TCO
- Recently signed additional 250,000 dt/d of firm transport with Virginia Power for its 1,300 MW Warren County, VA facility for May 2014
  - Announced additional generation needs for May 2015
- Other power growth expected with EPA rules going into effect
NGT&S Tariff Services

• Key Issue for Generators:
  – Day-ahead Forecast of Dispatch for Timely Cycle Nominations
  – Short or No-notice and Mid-Day Start-Ups
  – Communication Protocols
  – Gas Quality

• Newly Implemented Services
  – Summer-Only Deployment of NTS (no-notice service)

• New Services in Development
  – Scheduling Variance Service (SVS)
  – Quick Notice Service (QNT)
  – Hourly/After-Hours Nomination Cycles (Comparable to TXG ENS Service)
  – High-Deliverability Storage Products (Eastern Storage Expansions)
  – Negotiated Rate OBAs
Industry Needs & Expectations

- Energy Policy and EPA Certainty (Rules Implementation)
- Coordination & Communication with ISO/RTOs:
  - NGT&S outreach with PJM in Q1 2011
  - Developing Communication Protocols
  - Exploring Opportunities to Close Scheduling Gap - Respective “Day”
- Solicit FERC Reconsideration of Past Rulings
  - Communications with Generators
  - No Bump Rule
- FERC Consideration of New “Outside the Box” Services
  - Good Example: TXG Enhanced Nomination Service (ENS)
  - Consider the Benefits to Consumers and Industry as Whole vs. Potential Impacts on a few Participants
The Evolving Relationship Between the Electric and Gas Industries

Discussion Points Presented to The Energy Bar Association 2011 Mid-Year Meeting December 1, 2011

Regina Y. Speed-Bost Partner Schiff Hardin, LLP
Disclaimer:

The thoughts and views contained in this presentation are my own and do not represent the views of Schiff Hardin LLP or its clients.
A Call For Industry Action?

Natural gas and electric regulatory issues are said to be intertwined more now than ever before.

- Natural gas as a fuel for electric generation
- Natural gas as a baseload fuel
- Natural gas as a back-up for intermittent generation resources
2004 Winter Disruptions

Severe Cold Temperatures January 14, 15 and 16, 2004

- Unprecedented winter demand on the region’s electricity and gas systems
  - electricity demand on January 14, Hour Ending 6:00 p.m., set a new record winter peak of 22,450 MW,
  - superseded the next day by a new winter record of 22,817 MW during Hour Ending 7:00 p.m.
- Peak hour, hourly real-time price in the electricity market rose to nearly $1,000/MWh
  - day-ahead gas prices at a number of locations on the New England gas system increased to nearly ten times their normal levels.
2004 Winter Disruptions

- Conditions continued throughout the next two days with additional outages

- ISO New England - “a primary cause of events in the power and natural gas markets in the middle of January 2004 was extremely cold weather across New England and the rest of the Northeast.”
2011 Winter Disruptions

Seven years later:

• February 4 - 7, 2011 - “frigid weather in the U.S. Southwest choked off natural gas supply in the region” as production wells froze, starving pipeline networks and forcing companies to draw maximum volumes from storage

  • “unusually cold temperatures” in the gas-producing Southwest “affected supply equal to 5 percent of U.S. consumption” shutting power plants and causing rolling blackouts

  • Pipeline *force majeure*
Analyzing the Events

NAESB Post-Winter 2004 Report:

“the differences between the natural gas and electric industries pose inherent challenges to the interaction of the industries.”
Operational Differences Between Electric Power Production and Natural Gas Production and Transportation

- The lead time necessary to prepare for load fluctuations is shorter for the electric industry than the natural gas industry due to the inherent physical limitations of natural gas.
- Due to the necessary response time of the electric industry, instrumentation is necessarily much more precise both as to placement and timing than is the instrumentation in the natural gas industry.
- The electric industry is required to maintain a reserve margin to manage peak loads. Natural gas pipelines build capacity to match firm contractual commitments which in many cases include the peaking needs of their customers. Significantly, natural gas pipelines have no cost recovery mechanism for capacity not supported by contracts.
NAESB Report

- The interstate natural gas industry and FERC have adopted a market-driven model wherein capacity is built to fulfill request of contract customers while the power industry manages between a market-driven model and a traditional utility model, wherein utility reliability is maintained while accommodating and supporting market-driven transactions. This difference in models underlies the differences in capacity construction decisions.

- Load curtailment prioritization is not consistent between industries for peak day accommodation.
INGAA Foundation Report

Focused on the increased use of renewable electric power generation and undertook the task of evaluating the increased use of natural gas-fired generation for firming renewable resources with a particular focus on the implications of increased use on natural gas transportation infrastructure planning and pricing.
FERC/NERC Report on Southwest Power Outages – Findings Regarding the Electric Industry

• Many Generators failed to adequately apply and institutionalize knowledge and recommendations from previous events.

• Existing mechanisms (rolling blackouts) worked to eliminate more widespread outages/collapses

• Transmission operators and distribution providers did not identify natural gas facilities (gathering facilities, processing plants, compressor stations) as critical and essential loads
FERC/NERC Report on Southwest Power Outages – Findings Regarding the Natural Gas Industry

- The combination of dramatically reduced supply and unprecedented high demand resulted in gas outages and shortages that occurred in the region.
- No evidence that interstate or intrastate pipeline design constraints, system limitations, or equipment failures contributed significantly to the gas outages.
- The pipeline network showed good flexibility in adjusting flows to meet demand and compensate for supply shortfalls.
Regulatory Possibilities

What issues might we see FERC address in the future?

• Regulations with the effect of requiring gas-fired generation to ensure sufficient gas transportation as well as gas supplies for generation.

• Rate mechanisms and structures that accommodate intermittency and back up (“firming”) support.

• Cost mechanisms that continue to disclose the true costs of electric power generation so that consumers can be price sensitized in their usage.

• Reliability Standards development that fosters reliability while encourages sustainability.
Regulatory Possibilities

Federal regulators should focus the debate on issues such as:

• What is the level of natural gas pipeline infrastructure that will be needed to firm intermittent generation while still meeting the needs of other gas transportation customers?

• How do industry and regulators ensure that natural gas pipelines can meet the operational needs of these back up gas-fired generators?

• How can industry and regulators ensure that these generators contract for the appropriate natural gas transportation service?

• Who will pay for necessary gas transportation infrastructure expansions and other added costs?
Questions?

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Natural Gas, The New Economy

Energy Bar Association

12/01/2011
Dominion (NYSE:D), headquartered in Richmond, VA, is one of the nation’s largest producers and transporters of energy, with a portfolio of approximately 27,600 megawatts of generation, 12,000 miles of natural gas transmission, gathering and storage pipeline and 6,000 miles of electric transmission lines. Dominion operates the nation’s largest natural gas storage system with 942 billion cubic feet of storage capacity and serves retail energy customers in 13 states.
Utility Generation
Balanced, Diverse Asset and Fuel Mix

2009 Electric Capacity by Fuel
- Coal: 30%
- Nuclear: 18%
- Natural Gas: 12%
- Oil: 13%
- Hydro/Other: 27%

2009 Electric Production by Fuel*
- Coal: 44%
- Nuclear: 42%
- Natural Gas: 12%
- Oil: 1%
- Hydro/Other: 1%
Driven by low gas costs and environmental regulations, electric utilities are investing in gas-fired generation.

Certainty in utilization of these projects is critical, so more electric utilities are contracting for firm transportation services.

New CC generation will have high capacity factors and look more like industrial load.
New gas generation technology will require 700+ lbs minimum pressure and additional compression.

New gas-fired generation facilities will have operational and environmental limits on their ability to substitute alternate fuels.

Peakers that traditionally relied on IT only (summer) utilities are now considering FT for double peak (winter).

Major challenge: firm transport costs can unacceptably burden low/mid capacity units.
There is increasing interest in promoting the use of renewable or alternative energy.

Many renewable generation facilities run intermittently and require backup for periods when the renewable power is unavailable.

Cheap prices and plentiful supplies make natural gas an ideal backup fuel.

While renewable projects are unlikely to contract for FT service, these projects will add additional market to the pipeline grid and will compete for IT service.
Joining an RTO benefits electric utilities:
- Additional electric installed capacity for utility member
- Short and long term reliability
- Multiple products offered by RTO
- Capacity Payments to Utility member

Utility obligation for receipt of capacity payment:
- Conduct capacity tests to validate installed capacity during the summer
- Schedule maintenance plans across RTO
- Offer generation capacity daily at a prescriptive cost calculation
- Offer members service including: Black Start, Spinning Reserve (Renewable Back-up), and Regulation Power

RTO reliability requirements may force electric utilities into FT for gas-fired generation.
Firm Transportation Needs: Major Issues

- New gas infrastructure is very expensive.
  - Mechanisms for cost recovery must be determined.
  - Will producers build to power plants?
- Regulated electric utilities should be able to recover reasonable costs through rates.
  - Will state regulators allow electric utilities to recover cost of FT?
- Merchant plants are at risk for all costs.
  - Can merchant plants risk the additional cost of FT?
Firm Transportation Needs: Major Issues

- FT must be reliable on a year-round basis
  - Summer maintenance of pipelines may not be possible if power plants are affected.
  - Who bears costs for RTO penalties if FT is disrupted?
- New gas infrastructure has a long lead time for construction
  - Long term transportation contracts need to be in place prior to power plant construction.
  - What happens if FT service is delayed?
Conclusions

- Growth in gas-fired generation (base load and intermediate load) by regulated utilities will present gas pipelines and producers with opportunities.
- Renewable generation will benefit as electric utilities grow their gas transportation portfolios.
- RTO’s through their members will provide renewable reserve capacity.
- Cost recovery will be an issue, with Merchant generators bearing the greatest financial risk.
- Pipelines will need to rethink maintenance schedules and focus on year-round reliability.
Questions

- With the electric grid’s increasing reliance on natural gas, will FERC mandate new gas transportation terms and conditions to accommodate generators?
- Will RTO’s have a public policy mandate to support use of renewable energy?
- Can commercial and operational drivers in the free market accomplish the integration of gas and power?
- How will merchant generators protect their investments?
Transmission Planning, Cost Allocation, Incentives and Renewable Integration
Transmission Planning, Cost Allocation, and Renewable Integration

Rob Gramlich
Senior Vice President, Public Policy
American Wind Energy Association
American Wind Energy Association

AWEA is the trade association for the US wind energy industry

- 2,500 business members including manufacturers, developers, transportation, utilities, construction, insurers, financial community and technical support and forecasting representing 75,000 wind jobs
- Develops policies and conducts analysis to support wind industry growth
- Execute wind industry’s legislative agenda
- Promotes wind energy through advocacy, advertising and media relations
- Convenes conferences and workshops to educate the public and bring industry members together.

Transmission Infrastructure Policy
Transmission Benefits Consumers, is Needed Anyway

- Transmission is 5-7% of a typical electric bill, while generation is typically >60%

- Transmission provides consumers with access to cheaper generation and creates competition, reducing the overall electric bill on net

- Much of the opposition to transmission comes from utilities and others who don’t want competition for their generating assets

- Transmission needed anyway to benefit consumers and improve reliability

- Transmission needed regardless of which energy future we choose, and a variety of resources are likely to use new transmission lines
Transmission Creates Multiple Broadly Shared Benefits

![Bar chart showing benefits and costs in billions per year. Costs are in purple and benefits are divided into CO2 Emissions Reductions, Property Taxes, Economic Activity, Reduced Power Losses, Electricity Cost Reduction, and Investment in New Transmission Lines.

Data Sources: “First Two Loops of SPP EHV Overlay Transmission Expansion, Analysis of Benefits and Costs” Performed by CRA International on behalf of Electric Transmission America, OGE Energy Corp. and Westar Energy, September, 2008]
Free Rider Problem

- Economic benefits of transmission outweigh costs:
  - Joint Coordinated System Plan: Benefit-Cost ratio of 1.7 to 1
  - Texas study: Transmission for wind pays for itself in 3 years
  - Reliability benefits
  - Fuel price volatility benefits
  - Benefits of connected renewables: environmental, economic development, energy security

- Consumers benefit, those who own generation sometimes do not.
Order 1000 contains many of the planning and cost allocation policies AWEA has advocated.

FERC has given the transmission planning regions broad discretion to develop customized planning and cost allocation methodologies:

- Effectiveness will be unclear until the regions make their compliance filings, and FERC weighs on these filings.
AWEA Comments on Order 1000 (con’t)

• AWEA filed for rehearing asking FERC:
  • to go further than requiring public policy requirements to be merely “considered” in transmission planning
  • take a hard line against compliance filings that fall short
  • ensure interregional cost allocation also follows the “beneficiary pays” principle

• AWEA has worked with Congress to generate support for FERC’s efforts, oppose legislation like Corker amendment
SPP’s Highway/Byway proposal broadly spreads costs of high-voltage transmission.

Proposal reflects fact that benefits of high-voltage transmission are broadly distributed.

FERC accepted SPP’s proposal in June 2010.
MISO Cost Allocation

- MISO’s interim (2009-2010) cost allocation assigned 90-100% of transmission costs to generators, making transmission investment very difficult.
- MISO’s 2010 proposal broadly spreads costs for “Multi-Value Projects,” which includes projects that help meet state renewable requirements, while keeping 90-100% cost allocation for other projects.
- AWEA asked FERC to provide greater clarity that renewable transmission projects fall under MVP.
- FERC accepted MISO’s proposal in December 2010.
Grid operations reforms
Grid Balkanization Impairs Wind Integration
Wind Integration Costs are Modest

- Even at wind penetration levels many times higher than today, wind integration costs are small, and many of these costs will be drastically lower once grid operating reforms are implemented.

<table>
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<tr>
<th>Date</th>
<th>Study</th>
<th>Wind Capacity Penetration (%)</th>
<th>Regulation Cost ($/MWh)</th>
<th>Load Following Cost ($/MWh)</th>
<th>Unit Commitment Cost ($/MWh)</th>
<th>Gas Supply Cost ($/MWh)</th>
<th>Total Operating Cost Impact ($/MWh)</th>
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Source: NREL
Technical solutions

- **Shorter dispatch intervals:**
  - NERC: “More frequent and shorter scheduling intervals for energy transactions may assist in the large-scale integration of variable generation.” (p. 61)
  - 80% reduction in Bonneville wind integration costs, 40-60% reduction in Avista costs

- **Larger balancing areas:** Midwest ISO estimates savings from consolidating its 26 balancing areas into one are 3.7 to 6.7 times greater than the costs. 2x more wind can be integrated in NSP after it joined MISO at same integration cost.

- **Ancillary Services markets** ensure that lowest-cost resources provide needed flexibility services.

- **Forecasting** (4-24 hour, integrated with dispatch)
FERC Integration Rulemaking

- Notice of Inquiry on integration issues in spring 2010, proposed rulemaking issued November 2010, comments submitted March 2011

AWEA comments on FERC’s three proposals:

- 1. Sub-hourly scheduling is a step in the right direction, should be expanded to include dispatch
- 2. Wind energy forecasting proposal is helpful, wind industry willing to step up and provide data
- 3. Proposed generator regulation service needs changes:
  - Cost should be broadly allocated like other integration costs, FERC precedent
  - Service should be non-spin, not regulation
  - Should not take effect until grid reforms are implemented
I. TRANSMISSION COST ALLOCATION AND PLANNING

AWEA has been steadfast in expressing its concern with the inadequate development of America’s power infrastructure. The insufficient, albeit increasing, pace of transmission development has led to the untenable situation where the electric grid is increasingly facing the threat of becoming inadequate to reliably and economically support the dynamic needs of a bulk electric system with new generation sources and growing demand. As a trade association representing the interests of the wind industry, AWEA is concerned that the lack of adequate transmission infrastructure will stifle the development of renewable resources that will prove critical to supplying the increased demand and achieving the energy policy and security goals of this nation.

AWEA believes that FERC has clear authority and responsibility to decide fair cost allocation. Allocating costs is a core responsibility of FERC and this initiative is well founded on a large body of law. We applaud FERC for its leadership in finalizing reforms in Order 1000 that could serve to cut the Gordian knot that is blocking investment in our aging power grid: ensuring all users pay their fair share of new lines. Preventing free-riding will also help improve grid reliability, and reduce electricity bills by facilitating access to lower cost resources, including wind energy. As such, Order 1000 represents a potentially significant step in addressing the shortcomings in past energy policy that have contributed to the insufficient pace of investment growth in transmission. However, the full meaning of Order 1000 will be determined when compliance filings are made implementing it, and we encourage FERC, prior to approving these filings, ensure that these compliance filings achieve the goals of Order 1000, ensuring artificial barriers are removed to getting needed transmission built.

A. Cost Allocation

As the Department of Energy’s Electricity Advisory Committee concluded in its January 2009 report, “cost allocation is the single largest impediment to any transmission development, especially across multiple [Regional Transmission Organizations (“RTOs”)] or across RTO and non-RTO regions.”

Past cost allocation methods have often been applied narrowly. Generally speaking, narrow cost

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1 “Keeping the Lights On in a New World,” A Report by the Electricity Advisory Committee, U.S. Department of Energy, January 2009 (“Electricity Advisory Committee Report”) at p. 50, available at: http://www.oe.energy.gov/DocumentsandMedia/adequacy_report_01-09-09.pdf. See also Reply Comments of the Federal Trade Commission, Docket No. AD09-8-000 at p. 8 ( “Existing cost recovery regulations rely on complex determinations of beneficiaries and often restrict cost recovery to limited geographic areas. Projects that cross more than one discrete local transmission planning or operating area can face severe challenges in gaining consistent and efficient agreements from multiple transmission planning, siting and cost recovery regulators.”).
allocation models, such as “participant funding,” are premised on the erroneous notion that expansions of the grid are caused by, and serve only to meet, the needs of specific new customers, that only those new customers are the beneficiaries of these expansions and that property rights associated with these expansions can be precisely defined and fairly allocated to these new customers so as to reflect whatever benefits might arise out of the network expansions they fund. But, there simply is no logical, much less fair, basis upon which to directly assign virtually all of the costs or benefits of a grid expansion to a particular customer or even a narrow set of customers. Doing so only would allow much larger groups of users to receive benefits free of charge. This free-rider problem ultimately delays much-needed investment.

Order 1000 sets out some clear guidelines so that RTOs and other transmission providers can develop just and reasonable cost allocation methodologies. These cost allocation methodologies will be driven by six overarching principles:

1. Cost must be allocated on a basis roughly commensurate with estimated benefits
2. Cost must not be allocated to those who do not benefit
3. RTO/ISO must not establish a benefit/cost ratio that excludes projects with significant benefits
4. Planning regions cannot allocate costs outside the region unless the adjoining region agrees
5. Planning regions must provide a transparent mechanism for determining benefits and beneficiaries
6. Planning regions must clearly explain different allocation methodologies if applicable

The Commission has given the transmission planning regions broad discretion to develop customized cost allocation methodologies based on the above-stated principles. Therefore, the effectiveness of this guidance will be unclear until the regions make their compliance filings, and FERC weighs on these filings. AWEA encourages FERC to ensure that these principles stand for something and ensure that all compliance filings achieve the goal of not creating barriers to future transmission development.

1. Roughly Commensurate Standard

Cost allocation methodologies should satisfy FERC’s cost causation principle. However, a just and reasonable cost allocation methodology does not demand exacting mathematical calculation capable of precisely apportioning causation. An overly precise methodology is not practical because both the costs to be allocated and the resulting benefits must be based on projections. The test of an acceptable cost allocation methodology, as articulated by the U.S. Court of Appeals for the Seventh Circuit, is that

We do not suggest that the Commission has to calculate benefits to the last penny or for that matter to the last million or ten million or perhaps hundred million dollars. . . . If it cannot quantify the benefits . . . but has an articulable and plausible reason to believe
that the benefits are at least roughly commensurate...then fine; the Commission can approve [a] proposed pricing scheme on that basis.  

In short, the Seventh Circuit stated its willingness to accept a methodology that apports costs broadly on a basis “roughly commensurate” with the benefits. Of course, the converse is also true – those that do not benefit should not receive an allocation of costs.

B. Transmission Planning

The Commission has recognized that “changes in the nation’s electric power industry since issuance of Order 890 required the Commission to consider additional reforms to transmission planning . . . to reflect these new circumstances.” 3 It had become apparent that that the regional transmission planning framework was “not sufficient, in and of itself, to ensure an open, transparent, inclusive, and comprehensive regional transmission planning process.” 4 Moreover, these transmission planning processes were inadequate for developing interregional projects, projects with extremely long lead times, and projects with non-traditional benefits, such as projects developed to bring renewables to market.

1. Public Policy Requirements

Transmission planning processes and cost allocation methodologies that unnecessarily restrict the types of benefits that are to be considered for evaluation of proposed projects and apportionment of costs are just as detrimental to transmission investment as narrowly applied cost allocation methodologies. Order 1000 attempts to expand the consideration of benefits in the planning process beyond easily quantifiable reliability and congestion benefits by directing that transmission planning regions consider projects developed to comply with public policy requirements. AWEA believes that the mere consideration of public policy requirements in the transmission process may not ensure that transmission planning regions properly evaluate projects developed to meet public policy requirements, such as renewable portfolio standards, in their planning process. Again, the impact of this requirement will be unclear until the regions make their compliance filings, and we encourage FERC to ensure that public policy requirements are truly being incorporated into transmission plans.

2. Inter-Regional Planning/Cost Allocation

Because renewable resources often are location-constrained and can, therefore, be remote from load centers, planning for renewable resources must consider that access to renewable resources might require long lines extending across or even beyond a region. Order 1000 addresses this issue by creating a framework for the sharing of information between regions and the coordination of regional and inter-regional planning processes. The requirement that regions share information at specified intervals and in common formats should facilitate a level of coordination that has not yet existed.

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2 Illinois Commerce Commission v. FERC, 576 F.3d 470, 476 (7th Cir., 2009).
3 Order 1000 at P 31.
4 Id. at 70.
between regions. The creation and coordination of regional and inter-regional planning processes, with the guidance provided by the Commission, represents the first step towards a structured interregional planning process capable of consistently accommodating the types of long lines that are generally needed to bring remote renewable resources to dense load centers.

II. RENEWABLE INTEGRATION

AWEA supports the Commission in its efforts to reduce discrimination and improve the efficiency of the transmission system as part of the variable energy resources (VER) NOPR. In that proceeding, AWEA challenged the direct assignment of integration costs (incremental ancillary service costs) to renewable energy sources when no other contributor to ancillary service costs is directly assigned their share. We noted the sizable integration costs associated with large central station conventional power plants, relative to sources whose variability is over a one or two hour period and therefore often less expensive to balance. There are also two factors we feel should receive special consideration by the Commission if it wants to achieve its stated goals in its final rule, particularly in light of recent developments: (a) the distinction between sub-hourly scheduling and sub-hourly dispatch; and (b) the operating reforms required as part of this NOPR should be required to be implemented before any Schedule 10 rate is charged to variable energy resources.

A. Scheduling vs. Dispatch

The Commission finds in the NOPR that hourly transmission scheduling exposes transmission customers to excessive or unduly discriminatory generator imbalance charges and does not provide sufficient flexibility for the effective and efficient operation of transmission systems. We support the Commission’s intent to significantly improve the efficiency and fairness of the power system by requiring transmission service providers to offer sub-hourly scheduling at intervals of 15 minutes or less. However, we have serious concerns that the Commission’s actions will fall short of the goal of making rates just and reasonable unless changes are made to the sub-hourly scheduling provisions proposed in the NOPR.

AWEA believes it is important to clarify the difference between sub-hourly transmission scheduling and sub-hourly generator dispatch. If the Commission merely requires sub-hourly scheduling, it will not achieve the full benefits of sub-hourly generator dispatch and, in turn, produce unjust and unreasonable rates for VERs. Sub-hourly scheduling only governs the scheduling of flows on the transmission system and, by itself, does not necessarily affect the frequency with which generators are dispatched. A transition to sub-hourly generator dispatch is the key to increasing the flexibility of the power system and for reducing the amount of imbalances and the amount of reserves that must be held, thereby reducing costs for all users of the grid.
B. Require Certain Grid Reforms Before Accepting Schedule 10 Rate Requests

AWEA believes that the Commission should require that Schedule 10 rates, which allows a transmission provider to recover the cost of providing regulation and frequency response service, not be charged until a transmission service provider has fully implemented the sub-hourly transmission scheduling and variable energy forecasting operating reforms in the VER NOPR, as well as the requirement discussed above for sub-hourly generator dispatch. As presently proposed, the NOPR only requires the reforms to be implemented if a transmission service provider is attempting to charge a different rate for Schedule 10 for a particular type of generation. We believe that to ensure just and reasonable rates, these reforms should be required before any Schedule 10 charge can be charged at all, especially the implementation of sub-hourly generator dispatch. Without the implementation of these reforms, full achievement of the benefits the Commission set out to achieve in the NOPR (i.e., eliminating outdated, inefficient, and discriminatory operating practices) will not be realized and the imposition of Schedule 10 would result in charges that are not just and reasonable. We also believe that any claimed obstacles to implementing these reforms made by transmission providers should be judged against the fact that these burdens are mostly the result of past intransigence of transmission providers to embrace such reforms. In addition, these reforms will bring direct and indirect for all transmission customers, not just VERs.
Order No. 1000: A Southeastern Perspective

Andrew Tunnell
Balch & Bingham LLP
Transmission Planning, Cost Allocation, Incentives and Renewable Integration
Energy Bar Association – Mid-Year Meeting
December 1, 2011
Transmission in the Southeast: A Robust Grid with Effective Transmission Planning

DOE’S 2009 Transmission Congestion Study:

- “Because the southeastern utilities build aggressively in advance of load, there is little economic or reliability congestion within the region.”

- “The SERC region has a unique philosophy with respect to electric system planning and construction: ‘The transmission system within SERC has been planned, designed and is operated such that the utilities generating resources with contracts to serve load are not constrained.’”
Transmission in the Southeast: A Robust Grid with Effective Transmission Planning

NERC Data Reinforces Robustness of Southeastern Grid:

- Even though SERC has only the 4\textsuperscript{th} largest geographic footprint of the 8 NERC Regional Entities, SERC has the largest number of circuit miles (100 kV and above) in the Eastern Interconnection.

- SERC is second nationally only to the Western Electricity Coordination Council, which covers 3 times SERC’s square mileage.

- SERC has nearly as many circuit miles of transmission as both the second and third largest Regional Entities (i.e., MRO and NPCC) combined.
Transmission in the Southeast: A Robust Grid with Effective Transmission Planning

September 10, 2009 Transmission Planning Technical Conference in Atlanta, GA (Docket No. AD09-8).

Transmission Providers and Load Serving Entities all concurred that Southeastern grid is robust and the Southeastern transmission planning processes are effective.
Order No. 1000: Existing Planning Processes are Unlawful

- Order No. 1000 holds that existing planning processes are unjust and unreasonable under FPA Section 206.

- But the problems that Order No. 1000 seeks to address are not problems in the Southeast.
“Public Policy” Requirements are Already Included in Southeastern Planning

- All pertinent federal and State legal requirements for native load are incorporated in State-regulated IRP planning.
- Third parties can effectuate whatever legal needs they might have necessitating transmission upgrades by making long-term firm reservations under OATTs and thereby acquiring physical rights to the transmission system.
Southeastern Utilities Do Not Have Federal “Rights of First Refusal”

Much of Order No. 1000 addresses perceived concerns with Rights of First Refusals (“ROFRs”) that some Transmission Owners have to construct new transmission.

Southeastern utilities have no such federal ROFRs, and I’m not aware of State ROFRs.
Southeastern Planning Processes are Thoroughly Coordinated

- **SEE NEXT SLIDE** (*E.g.*, NCTPC)

- Regional Processes are thoroughly coordinated: *E.g.*, NCTPC and bilateral arrangements.

- Interregional processes are thoroughly coordinated: SERC reliability assessments, RFC, ERAG/MMWG, SIRPP economic studies, bilateral arrangements, and interactions with neighboring planning regions (*e.g.*, SERTP, SCRTP).

- Also – EIPC, EISPC.
Associated Gas Distributors

AGD concluded, in part, that applying a nation-wide remedy to a problem of limited applicability was inappropriate.

As demonstrated above, problems raised in Order No. 1000 are not problems for the Southeast.
Order No. 1000: Based on Theory Not Fact

This holding is not based upon “record evidence of abuse” but, pursuant to the *National Fuels* decision, upon a “theoretical threat” [P 53].

At its essence, Order No. 1000’s “theory” appears to be the Commission’s belief that Order No. 1000’s additional transmission planning and cost allocation requirements “may”, “could”, or will “potentially” do a better job of identifying appropriate upgrades than the processes currently deemed appropriate by the industry. [See PP 6, 7, 78, 47, 81, 284, 285, 559, 579.]
National Fuels: An Authorization to Base Agency Action on Theory Alone or a Warning?

National Fuels: Overturned FERC’s Order No. 2004 (involving Standards of Conduct). FERC held that Order No. 2004 was supported by both Fact and Theory. The Court found no factual basis and overturned the Order on that basis.

The court did hold: “If FERC chooses to rely solely on a theoretical threat [on remand], it will need to explain how the potential danger of improper communications between pipelines and their non-marketing affiliates, unsupported by a record of abuse, justifies such costly prophylactic rules. FERC would need to explain how the individual complaint procedures under Section 5 of the Natural Gas Act does not suffice to ensure that pipelines are not abusing their relationships with non-marketing affiliates.”
As applied to Southeastern Utilities, Does Order No. 1000’s Theory Satisfy *National Fuel*?

- Is Order No. 1000’s “theory” that its requirements may produce additional benefits an established “theory” or a business decision?
- Compare Order No. 1000’s “theory” with that underlying *National Fuels* (*i.e.*, preferential access to information was alleged to result in inappropriate competitive benefits) and *Electricity Consumer Resource Council* (*i.e.*, economic theory of marginal pricing).
Additional Planning Processes/Coordination Are Not Reasonably Expected to Produce Benefits in the Southeast

- *National Fuels*: Addressing the theoretical threat must be justified by benefits.
- In the Southeast, three drivers for transmission expansion: i) integrating new resources; ii) load growth; and iii) OATT requests. The first two are effectuated through State-Regulated IRP Planning.
- Order No. 1000 brings no new drivers for transmission expansion – it makes clear that it is not requiring IRP, and OATT requests are already incorporated in existing planning processes.
- With no new drivers for transmission expansion in the Southeast, Order No. 1000 should only result in incremental expansion if its additional coordination requirements identify a previously unidentified enhancement – but existing transmission planners’ job is to identify such enhancements.
Order No. 1000 Compliance?

- Compliance in the Southeast complicated by lack of a clear problem to be addressed.

- “[T]he existing regional transmission planning processes that many utilities relied upon to comply with the requirements of Order No. 890 may require only modest changes…” [n. 142].
Energy Bar Association  
Mid-Year Meeting  
Vincent P. Duane  
December 1, 2011
• Need more transmission generally (under investment)
• Need more transmission to support changing supply preferences (public policy)
• Transmission not coming as fast as necessary
• Transmission not coming in where needed
• Designed to “liberalize” transmission as an analog to how Order No. 888 “liberalized” generation/supply side.

• Merchant transmission v. merchant generation: different predicates?

• Logic of competition in transmission development?
## PJM: Do We Have a Transmission Development Problem?

<table>
<thead>
<tr>
<th>Baseline Reinforcements</th>
<th>July 26, 2011 BOM Meeting</th>
<th>October 18, 2011 BOM Meeting</th>
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<tr>
<td>Generation &amp; Merchant Transmission Network Upgrades and Direct Connection for Queues A to U4</td>
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<td>$17,231M</td>
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<tr>
<td></td>
<td>$3,412 M</td>
<td>$3,478 M</td>
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<tr>
<td>Total RTEP Plan</td>
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<td>$20,709 M</td>
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PJM: Do We Have Challenges Developing Transmission?

### Sum of Cost Estimate

<table>
<thead>
<tr>
<th>Type</th>
<th>Active</th>
<th>In-Service</th>
<th>Under Construction</th>
<th>Grand Total</th>
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<td>Network</td>
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<td>Attachment Facility</td>
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<td>605</td>
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<tr>
<td>Grand Total</td>
<td>14,834</td>
<td>3,862</td>
<td>2,013</td>
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</tr>
</tbody>
</table>

The graph shows the cost estimates for Baseline, Network, and Attachment Facility, categorized into Active, In-Service, and Under Construction phases.
PJM: Do We Challenges Developing Transmission?

- PJM’s RTEP process has received requests to interconnect over 310,000 MW since 1997
- PJM coordinated system enhancements have accommodated over 27,000 MW of new generation
- 315 generation projects have gone into service

310,000 MW of requests since 1997

27,000 MW of new generation

315 generation projects in service

As of March 2011
The right-of-way route shown on this map is for illustrative purposes only and may not depict the actual route that may eventually be chosen. Substation locations may also be modified if more beneficial connections are determined by PJM.
• 2011 RTEP assumptions show fewer reliability criteria violations, later in the planning horizon
• In February 2011 the Board suspended the project pending additional RTEP analysis
• Mid-Atlantic Power Pathway Project

• 2011 RTEP shows fewer reliability criteria violations, later in the planning horizon

• In August 2011 the Board suspended the project pending additional RTEP analysis
Due to the delays, the entire line is not expected until June 1, 2015

Updated analysis using the 2011 RTEP assumptions show fewer violations in 2012

Critical to bringing new sources of supply into constrained northern New Jersey

Named to the new federal inter-agency “Rapid Response Team” list of projects
Will Order No. 1000 Improve Transmission Development in PJM?

- Generally Eliminating ROFR
  - No evidence incumbents disinclined to develop
  - Complex implementation issues
- Considering Public Policy
  - Transmission projects already underway in PJM not targeted to support renewables, but in the right place to accommodate renewables
  - Siting and the need for collective state input in the planning process
- Cost Allocation
• PJM Planning process can be improved by introducing:
  - Common sense exercise of engineering judgment
  - Accept proposition that uncertainty necessary means some “art” and not all “science”
  - Ranges, sensitivity and scenario analysis to define planning criteria violations

• Order No. 1000 presents an opportunity to introduce these critical refinements (Order No. 1000, ¶ 224)
NOTES
Electric Industry Consolidation
and Merger Policy
Horizontal Merger Guidelines

U.S. Department of Justice

and the

Federal Trade Commission

Issued: August 19, 2010
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1. Overview

These Guidelines outline the principal analytical techniques, practices, and the enforcement policy of the Department of Justice and the Federal Trade Commission (the “Agencies”) with respect to mergers and acquisitions involving actual or potential competitors (“horizontal mergers”) under the federal antitrust laws.¹ The relevant statutory provisions include Section 7 of the Clayton Act, 15 U.S.C. § 18, Sections 1 and 2 of the Sherman Act, 15 U.S.C. §§ 1, 2, and Section 5 of the Federal Trade Commission Act, 15 U.S.C. § 45. Most particularly, Section 7 of the Clayton Act prohibits mergers if “in any line of commerce or in any activity affecting commerce in any section of the country, the effect of such acquisition may be substantially to lessen competition, or to tend to create a monopoly.”

The Agencies seek to identify and challenge competitively harmful mergers while avoiding unnecessary interference with mergers that are either competitively beneficial or neutral. Most merger analysis is necessarily predictive, requiring an assessment of what will likely happen if a merger proceeds as compared to what will likely happen if it does not. Given this inherent need for prediction, these Guidelines reflect the congressional intent that merger enforcement should interdict competitive problems in their incipiency and that certainty about anticompetitive effect is seldom possible and not required for a merger to be illegal.

These Guidelines describe the principal analytical techniques and the main types of evidence on which the Agencies usually rely to predict whether a horizontal merger may substantially lessen competition. They are not intended to describe how the Agencies analyze cases other than horizontal mergers. These Guidelines are intended to assist the business community and antitrust practitioners by increasing the transparency of the analytical process underlying the Agencies’ enforcement decisions. They may also assist the courts in developing an appropriate framework for interpreting and applying the antitrust laws in the horizontal merger context.

These Guidelines should be read with the awareness that merger analysis does not consist of uniform application of a single methodology. Rather, it is a fact-specific process through which the Agencies, guided by their extensive experience, apply a range of analytical tools to the reasonably available and reliable evidence to evaluate competitive concerns in a limited period of time. Where these Guidelines provide examples, they are illustrative and do not exhaust the applications of the relevant principle.²

¹ These Guidelines replace the Horizontal Merger Guidelines issued in 1992, revised in 1997. They reflect the ongoing accumulation of experience at the Agencies. The Commentary on the Horizontal Merger Guidelines issued by the Agencies in 2006 remains a valuable supplement to these Guidelines. These Guidelines may be revised from time to time as necessary to reflect significant changes in enforcement policy, to clarify existing policy, or to reflect new learning. These Guidelines do not cover vertical or other types of non-horizontal acquisitions.

² These Guidelines are not intended to describe how the Agencies will conduct the litigation of cases they decide to bring. Although relevant in that context, these Guidelines neither dictate nor exhaust the range of evidence the Agencies may introduce in litigation.
The unifying theme of these Guidelines is that mergers should not be permitted to create, enhance, or entrench market power or to facilitate its exercise. For simplicity of exposition, these Guidelines generally refer to all of these effects as enhancing market power. A merger enhances market power if it is likely to encourage one or more firms to raise price, reduce output, diminish innovation, or otherwise harm customers as a result of diminished competitive constraints or incentives. In evaluating how a merger will likely change a firm’s behavior, the Agencies focus primarily on how the merger affects conduct that would be most profitable for the firm.

A merger can enhance market power simply by eliminating competition between the merging parties. This effect can arise even if the merger causes no changes in the way other firms behave. Adverse competitive effects arising in this manner are referred to as “unilateral effects.” A merger also can enhance market power by increasing the risk of coordinated, accommodating, or interdependent behavior among rivals. Adverse competitive effects arising in this manner are referred to as “coordinated effects.” In any given case, either or both types of effects may be present, and the distinction between them may be blurred.

These Guidelines principally describe how the Agencies analyze mergers between rival suppliers that may enhance their market power as sellers. Enhancement of market power by sellers often elevates the prices charged to customers. For simplicity of exposition, these Guidelines generally discuss the analysis in terms of such price effects. Enhanced market power can also be manifested in non-price terms and conditions that adversely affect customers, including reduced product quality, reduced product variety, reduced service, or diminished innovation. Such non-price effects may coexist with price effects, or can arise in their absence. When the Agencies investigate whether a merger may lead to a substantial lessening of non-price competition, they employ an approach analogous to that used to evaluate price competition. Enhanced market power may also make it more likely that the merged entity can profitably and effectively engage in exclusionary conduct. Regardless of how enhanced market power likely would be manifested, the Agencies normally evaluate mergers based on their impact on customers. The Agencies examine effects on either or both of the direct customers and the final consumers. The Agencies presume, absent convincing evidence to the contrary, that adverse effects on direct customers also cause adverse effects on final consumers.

Enhancement of market power by buyers, sometimes called “monopsony power,” has adverse effects comparable to enhancement of market power by sellers. The Agencies employ an analogous framework to analyze mergers between rival purchasers that may enhance their market power as buyers. See Section 12.

2. Evidence of Adverse Competitive Effects

The Agencies consider any reasonably available and reliable evidence to address the central question of whether a merger may substantially lessen competition. This section discusses several categories and sources of evidence that the Agencies, in their experience, have found most informative in predicting the likely competitive effects of mergers. The list provided here is not exhaustive. In any given case, reliable evidence may be available in only some categories or from some sources. For each category of evidence, the Agencies consider evidence indicating that the merger may enhance competition as well as evidence indicating that it may lessen competition.
2.1 Types of Evidence

2.1.1 Actual Effects Observed in Consummated Mergers

When evaluating a consummated merger, the ultimate issue is not only whether adverse competitive effects have already resulted from the merger, but also whether such effects are likely to arise in the future. Evidence of observed post-merger price increases or other changes adverse to customers is given substantial weight. The Agencies evaluate whether such changes are anticompetitive effects resulting from the merger, in which case they can be dispositive. However, a consummated merger may be anticompetitive even if such effects have not yet been observed, perhaps because the merged firm may be aware of the possibility of post-merger antitrust review and moderating its conduct. Consequently, the Agencies also consider the same types of evidence they consider when evaluating unconsummated mergers.

2.1.2 Direct Comparisons Based on Experience

The Agencies look for historical events, or “natural experiments,” that are informative regarding the competitive effects of the merger. For example, the Agencies may examine the impact of recent mergers, entry, expansion, or exit in the relevant market. Effects of analogous events in similar markets may also be informative.

The Agencies also look for reliable evidence based on variations among similar markets. For example, if the merging firms compete in some locales but not others, comparisons of prices charged in regions where they do and do not compete may be informative regarding post-merger prices. In some cases, however, prices are set on such a broad geographic basis that such comparisons are not informative. The Agencies also may examine how prices in similar markets vary with the number of significant competitors in those markets.

2.1.3 Market Shares and Concentration in a Relevant Market

The Agencies give weight to the merging parties’ market shares in a relevant market, the level of concentration, and the change in concentration caused by the merger. See Sections 4 and 5. Mergers that cause a significant increase in concentration and result in highly concentrated markets are presumed to be likely to enhance market power, but this presumption can be rebutted by persuasive evidence showing that the merger is unlikely to enhance market power.

2.1.4 Substantial Head-to-Head Competition

The Agencies consider whether the merging firms have been, or likely will become absent the merger, substantial head-to-head competitors. Such evidence can be especially relevant for evaluating adverse unilateral effects, which result directly from the loss of that competition. See Section 6. This evidence can also inform market definition. See Section 4.

2.1.5 Disruptive Role of a Merging Party

The Agencies consider whether a merger may lessen competition by eliminating a “maverick” firm, i.e., a firm that plays a disruptive role in the market to the benefit of customers. For example, if one of the merging firms has a strong incumbency position and the other merging firm threatens to
disrupt market conditions with a new technology or business model, their merger can involve the loss of actual or potential competition. Likewise, one of the merging firms may have the incentive to take the lead in price cutting or other competitive conduct or to resist increases in industry prices. A firm that may discipline prices based on its ability and incentive to expand production rapidly using available capacity also can be a maverick, as can a firm that has often resisted otherwise prevailing industry norms to cooperate on price setting or other terms of competition.

### 2.2 Sources of Evidence

The Agencies consider many sources of evidence in their merger analysis. The most common sources of reasonably available and reliable evidence are the merging parties, customers, other industry participants, and industry observers.

#### 2.2.1 Merging Parties

The Agencies typically obtain substantial information from the merging parties. This information can take the form of documents, testimony, or data, and can consist of descriptions of competitively relevant conditions or reflect actual business conduct and decisions. Documents created in the normal course are more probative than documents created as advocacy materials in merger review. Documents describing industry conditions can be informative regarding the operation of the market and how a firm identifies and assesses its rivals, particularly when business decisions are made in reliance on the accuracy of those descriptions. The business decisions taken by the merging firms also can be informative about industry conditions. For example, if a firm sets price well above incremental cost, that normally indicates either that the firm believes its customers are not highly sensitive to price (not in itself of antitrust concern, see Section 4.1.3) or that the firm and its rivals are engaged in coordinated interaction (see Section 7). Incremental cost depends on the relevant increment in output as well as on the time period involved, and in the case of large increments and sustained changes in output it may include some costs that would be fixed for smaller increments of output or shorter time periods.

Explicit or implicit evidence that the merging parties intend to raise prices, reduce output or capacity, reduce product quality or variety, withdraw products or delay their introduction, or curtail research and development efforts after the merger, or explicit or implicit evidence that the ability to engage in such conduct motivated the merger, can be highly informative in evaluating the likely effects of a merger. Likewise, the Agencies look for reliable evidence that the merger is likely to result in efficiencies. The Agencies give careful consideration to the views of individuals whose responsibilities, expertise, and experience relating to the issues in question provide particular indicia of reliability. The financial terms of the transaction may also be informative regarding competitive effects. For example, a purchase price in excess of the acquired firm’s stand-alone market value may indicate that the acquiring firm is paying a premium because it expects to be able to reduce competition or to achieve efficiencies.

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3 High margins commonly arise for products that are significantly differentiated. Products involving substantial fixed costs typically will be developed only if suppliers expect there to be enough differentiation to support margins sufficient to cover those fixed costs. High margins can be consistent with incumbent firms earning competitive returns.
2.2.2 **Customers**

Customers can provide a variety of information to the Agencies, ranging from information about their own purchasing behavior and choices to their views about the effects of the merger itself.

Information from customers about how they would likely respond to a price increase, and the relative attractiveness of different products or suppliers, may be highly relevant, especially when corroborated by other evidence such as historical purchasing patterns and practices. Customers also can provide valuable information about the impact of historical events such as entry by a new supplier.

The conclusions of well-informed and sophisticated customers on the likely impact of the merger itself can also help the Agencies investigate competitive effects, because customers typically feel the consequences of both competitively beneficial and competitively harmful mergers. In evaluating such evidence, the Agencies are mindful that customers may oppose, or favor, a merger for reasons unrelated to the antitrust issues raised by that merger.

When some customers express concerns about the competitive effects of a merger while others view the merger as beneficial or neutral, the Agencies take account of this divergence in using the information provided by customers and consider the likely reasons for such divergence of views. For example, if for regulatory reasons some customers cannot buy imported products, while others can, a merger between domestic suppliers may harm the former customers even if it leaves the more flexible customers unharmed. See Section 3.

When direct customers of the merging firms compete against one another in a downstream market, their interests may not be aligned with the interests of final consumers, especially if the direct customers expect to pass on any anticompetitive price increase. A customer that is protected from adverse competitive effects by a long-term contract, or otherwise relatively immune from the merger’s harmful effects, may even welcome an anticompetitive merger that provides that customer with a competitive advantage over its downstream rivals.

*Example 1:* As a result of the merger, Customer C will experience a price increase for an input used in producing its final product, raising its costs. Customer C’s rivals use this input more intensively than Customer C, and the same price increase applied to them will raise their costs more than it raises Customer C’s costs. On balance, Customer C may benefit from the merger even though the merger involves a substantial lessening of competition.

2.2.3 **Other Industry Participants and Observers**

Suppliers, indirect customers, distributors, other industry participants, and industry analysts can also provide information helpful to a merger inquiry. The interests of firms selling products complementary to those offered by the merging firms often are well aligned with those of customers, making their informed views valuable.

Information from firms that are rivals to the merging parties can help illuminate how the market operates. The interests of rival firms often diverge from the interests of customers, since customers normally lose, but rival firms gain, if the merged entity raises its prices. For that reason, the Agencies do not routinely rely on the overall views of rival firms regarding the competitive effects of the
merger. However, rival firms may provide relevant facts, and even their overall views may be instructive, especially in cases where the Agencies are concerned that the merged entity may engage in exclusionary conduct.

Example 2: Merging Firms A and B operate in a market in which network effects are significant, implying that any firm’s product is significantly more valuable if it commands a large market share or if it is interconnected with others that in aggregate command such a share. Prior to the merger, they and their rivals voluntarily interconnect with one another. The merger would create an entity with a large enough share that a strategy of ending voluntary interconnection would have a dangerous probability of creating monopoly power in this market. The interests of rivals and of consumers would be broadly aligned in preventing such a merger.

3. Targeted Customers and Price Discrimination

When examining possible adverse competitive effects from a merger, the Agencies consider whether those effects vary significantly for different customers purchasing the same or similar products. Such differential impacts are possible when sellers can discriminate, e.g., by profitably raising price to certain targeted customers but not to others. The possibility of price discrimination influences market definition (see Section 4), the measurement of market shares (see Section 5), and the evaluation of competitive effects (see Sections 6 and 7).

When price discrimination is feasible, adverse competitive effects on targeted customers can arise, even if such effects will not arise for other customers. A price increase for targeted customers may be profitable even if a price increase for all customers would not be profitable because too many other customers would substitute away. When discrimination is reasonably likely, the Agencies may evaluate competitive effects separately by type of customer. The Agencies may have access to information unavailable to customers that is relevant to evaluating whether discrimination is reasonably likely.

For price discrimination to be feasible, two conditions typically must be met: differential pricing and limited arbitrage.

First, the suppliers engaging in price discrimination must be able to price differently to targeted customers than to other customers. This may involve identification of individual customers to which different prices are offered or offering different prices to different types of customers based on observable characteristics.

Example 3: Suppliers can distinguish large buyers from small buyers. Large buyers are more likely than small buyers to self-supply in response to a significant price increase. The merger may lead to price discrimination against small buyers, harming them, even if large buyers are not harmed. Such discrimination can occur even if there is no discrete gap in size between the classes of large and small buyers.

In other cases, suppliers may be unable to distinguish among different types of customers but can offer multiple products that sort customers based on their purchase decisions.

Second, the targeted customers must not be able to defeat the price increase of concern by arbitrage, e.g., by purchasing indirectly from or through other customers. Arbitrage may be difficult if it would void warranties or make service more difficult or costly for customers. Arbitrage is inherently impossible for many services. Arbitrage between customers at different geographic locations may be
impractical due to transportation costs. Arbitrage on a modest scale may be possible but sufficiently costly or limited that it would not deter or defeat a discriminatory pricing strategy.

4. Market Definition

When the Agencies identify a potential competitive concern with a horizontal merger, market definition plays two roles. First, market definition helps specify the line of commerce and section of the country in which the competitive concern arises. In any merger enforcement action, the Agencies will normally identify one or more relevant markets in which the merger may substantially lessen competition. Second, market definition allows the Agencies to identify market participants and measure market shares and market concentration. See Section 5. The measurement of market shares and market concentration is not an end in itself, but is useful to the extent it illuminates the merger’s likely competitive effects.

The Agencies’ analysis need not start with market definition. Some of the analytical tools used by the Agencies to assess competitive effects do not rely on market definition, although evaluation of competitive alternatives available to customers is always necessary at some point in the analysis.

Evidence of competitive effects can inform market definition, just as market definition can be informative regarding competitive effects. For example, evidence that a reduction in the number of significant rivals offering a group of products causes prices for those products to rise significantly can itself establish that those products form a relevant market. Such evidence also may more directly predict the competitive effects of a merger, reducing the role of inferences from market definition and market shares.

Where analysis suggests alternative and reasonably plausible candidate markets, and where the resulting market shares lead to very different inferences regarding competitive effects, it is particularly valuable to examine more direct forms of evidence concerning those effects.

Market definition focuses solely on demand substitution factors, i.e., on customers’ ability and willingness to substitute away from one product to another in response to a price increase or a corresponding non-price change such as a reduction in product quality or service. The responsive actions of suppliers are also important in competitive analysis. They are considered in these Guidelines in the sections addressing the identification of market participants, the measurement of market shares, the analysis of competitive effects, and entry.

Customers often confront a range of possible substitutes for the products of the merging firms. Some substitutes may be closer, and others more distant, either geographically or in terms of product attributes and perceptions. Additionally, customers may assess the proximity of different products differently. When products or suppliers in different geographic areas are substitutes for one another to varying degrees, defining a market to include some substitutes and exclude others is inevitably a simplification that cannot capture the full variation in the extent to which different products compete against each other. The principles of market definition outlined below seek to make this inevitable simplification as useful and informative as is practically possible. Relevant markets need not have precise metes and bounds.
Defining a market broadly to include relatively distant product or geographic substitutes can lead to misleading market shares. This is because the competitive significance of distant substitutes is unlikely to be commensurate with their shares in a broad market. Although excluding more distant substitutes from the market inevitably understates their competitive significance to some degree, doing so often provides a more accurate indicator of the competitive effects of the merger than would the alternative of including them and overstating their competitive significance as proportional to their shares in an expanded market.

Example 4: Firms A and B, sellers of two leading brands of motorcycles, propose to merge. If Brand A motorcycle prices were to rise, some buyers would substitute to Brand B, and some others would substitute to cars. However, motorcycle buyers see Brand B motorcycles as much more similar to Brand A motorcycles than are cars. Far more cars are sold than motorcycles. Evaluating shares in a market that includes cars would greatly underestimate the competitive significance of Brand B motorcycles in constraining Brand A’s prices and greatly overestimate the significance of cars.

Market shares of different products in narrowly defined markets are more likely to capture the relative competitive significance of these products, and often more accurately reflect competition between close substitutes. As a result, properly defined antitrust markets often exclude some substitutes to which some customers might turn in the face of a price increase even if such substitutes provide alternatives for those customers. However, a group of products is too narrow to constitute a relevant market if competition from products outside that group is so ample that even the complete elimination of competition within the group would not significantly harm either direct customers or downstream consumers. The hypothetical monopolist test (see Section 4.1.1) is designed to ensure that candidate markets are not overly narrow in this respect.

The Agencies implement these principles of market definition flexibly when evaluating different possible candidate markets. Relevant antitrust markets defined according to the hypothetical monopolist test are not always intuitive and may not align with how industry members use the term “market.”

Section 4.1 describes the principles that apply to product market definition, and gives guidance on how the Agencies most often apply those principles. Section 4.2 describes how the same principles apply to geographic market definition. Although discussed separately for simplicity of exposition, the principles described in Sections 4.1 and 4.2 are combined to define a relevant market, which has both a product and a geographic dimension. In particular, the hypothetical monopolist test is applied to a group of products together with a geographic region to determine a relevant market.

4.1 Product Market Definition

When a product sold by one merging firm (Product A) competes against one or more products sold by the other merging firm, the Agencies define a relevant product market around Product A to evaluate the importance of that competition. Such a relevant product market consists of a group of substitute products including Product A. Multiple relevant product markets may thus be identified.

4.1.1 The Hypothetical Monopolist Test

The Agencies employ the hypothetical monopolist test to evaluate whether groups of products in candidate markets are sufficiently broad to constitute relevant antitrust markets. The Agencies use the
hypothetical monopolist test to identify a set of products that are reasonably interchangeable with a product sold by one of the merging firms.

The hypothetical monopolist test requires that a product market contain enough substitute products so that it could be subject to post-merger exercise of market power significantly exceeding that existing absent the merger. Specifically, the test requires that a hypothetical profit-maximizing firm, not subject to price regulation, that was the only present and future seller of those products (“hypothetical monopolist”) likely would impose at least a small but significant and non-transitory increase in price (“SSNIP”) on at least one product in the market, including at least one product sold by one of the merging firms. For the purpose of analyzing this issue, the terms of sale of products outside the candidate market are held constant. The SSNIP is employed solely as a methodological tool for performing the hypothetical monopolist test; it is not a tolerance level for price increases resulting from a merger.

Groups of products may satisfy the hypothetical monopolist test without including the full range of substitutes from which customers choose. The hypothetical monopolist test may identify a group of products as a relevant market even if customers would substitute significantly to products outside that group in response to a price increase.

**Example 5:** Products A and B are being tested as a candidate market. Each sells for $100, has an incremental cost of $60, and sells 1200 units. For every dollar increase in the price of Product A, for any given price of Product B, Product A loses twenty units of sales to products outside the candidate market and ten units of sales to Product B, and likewise for Product B. Under these conditions, economic analysis shows that a hypothetical profit-maximizing monopolist controlling Products A and B would raise both of their prices by ten percent, to $110. Therefore, Products A and B satisfy the hypothetical monopolist test using a five percent SSNIP, and indeed for any SSNIP size up to ten percent. This is true even though two-thirds of the sales lost by one product when it raises its price are diverted to products outside the relevant market.

When applying the hypothetical monopolist test to define a market around a product offered by one of the merging firms, if the market includes a second product, the Agencies will normally also include a third product if that third product is a closer substitute for the first product than is the second product. The third product is a closer substitute if, in response to a SSNIP on the first product, greater revenues are diverted to the third product than to the second product.

**Example 6:** In Example 5, suppose that half of the unit sales lost by Product A when it raises its price are diverted to Product C, which also has a price of $100, while one-third are diverted to Product B. Product C is a closer substitute for Product A than is Product B. Thus Product C will normally be included in the relevant market, even though Products A and B together satisfy the hypothetical monopolist test.

The hypothetical monopolist test ensures that markets are not defined too narrowly, but it does not lead to a single relevant market. The Agencies may evaluate a merger in any relevant market.

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4 If the pricing incentives of the firms supplying the products in the candidate market differ substantially from those of the hypothetical monopolist, for reasons other than the latter’s control over a larger group of substitutes, the Agencies may instead employ the concept of a hypothetical profit-maximizing cartel comprised of the firms (with all their products) that sell the products in the candidate market. This approach is most likely to be appropriate if the merging firms sell products outside the candidate market that significantly affect their pricing incentives for products in the candidate market. This could occur, for example, if the candidate market is one for durable equipment and the firms selling that equipment derive substantial net revenues from selling spare parts and service for that equipment.
satisfying the test, guided by the overarching principle that the purpose of defining the market and measuring market shares is to illuminate the evaluation of competitive effects. Because the relative competitive significance of more distant substitutes is apt to be overstated by their share of sales, when the Agencies rely on market shares and concentration, they usually do so in the smallest relevant market satisfying the hypothetical monopolist test.

Example 7: In Example 4, including cars in the market will lead to misleadingly small market shares for motorcycle producers. Unless motorcycles fail the hypothetical monopolist test, the Agencies would not include cars in the market in analyzing this motorcycle merger.

4.1.2 Benchmark Prices and SSNIP Size

The Agencies apply the SSNIP starting from prices that would likely prevail absent the merger. If prices are not likely to change absent the merger, these benchmark prices can reasonably be taken to be the prices prevailing prior to the merger.\(^5\) If prices are likely to change absent the merger, e.g., because of innovation or entry, the Agencies may use anticipated future prices as the benchmark for the test. If prices might fall absent the merger due to the breakdown of pre-merger coordination, the Agencies may use those lower prices as the benchmark for the test. In some cases, the techniques employed by the Agencies to implement the hypothetical monopolist test focus on the difference in incentives between pre-merger firms and the hypothetical monopolist and do not require specifying the benchmark prices.

The SSNIP is intended to represent a “small but significant” increase in the prices charged by firms in the candidate market for the value they contribute to the products or services used by customers. This properly directs attention to the effects of price changes commensurate with those that might result from a significant lessening of competition caused by the merger. This methodology is used because normally it is possible to quantify “small but significant” adverse price effects on customers and analyze their likely reactions, not because price effects are more important than non-price effects.

The Agencies most often use a SSNIP of five percent of the price paid by customers for the products or services to which the merging firms contribute value. However, what constitutes a “small but significant” increase in price, commensurate with a significant loss of competition caused by the merger, depends upon the nature of the industry and the merging firms’ positions in it, and the Agencies may accordingly use a price increase that is larger or smaller than five percent. Where explicit or implicit prices for the firms’ specific contribution to value can be identified with reasonable clarity, the Agencies may base the SSNIP on those prices.

Example 8: In a merger between two oil pipelines, the SSNIP would be based on the price charged for transporting the oil, not on the price of the oil itself. If pipelines buy the oil at one end and sell it at the other, the price charged for transporting the oil is implicit, equal to the difference between the price paid for oil at the input end and the price charged for oil at the output end. The relevant product sold by the pipelines is better described as “pipeline transportation of oil from point A to point B” than as “oil at point B.”

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\(^5\) Market definition for the evaluation of non-merger antitrust concerns such as monopolization or facilitating practices will differ in this respect if the effects resulting from the conduct of concern are already occurring at the time of evaluation.
Example 9: In a merger between two firms that install computers purchased from third parties, the SSNIP would be based on their fees, not on the price of installed computers. If these firms purchase the computers and charge their customers one package price, the implicit installation fee is equal to the package charge to customers less the price of the computers.

Example 10: In Example 9, suppose that the prices paid by the merging firms to purchase computers are opaque, but account for at least ninety-five percent of the prices they charge for installed computers, with profits or implicit fees making up five percent of those prices at most. A five percent SSNIP on the total price paid by customers would at least double those fees or profits. Even if that would be unprofitable for a hypothetical monopolist, a significant increase in fees might well be profitable. If the SSNIP is based on the total price paid by customers, a lower percentage will be used.

4.1.3 Implementing the Hypothetical Monopolist Test

The hypothetical monopolist’s incentive to raise prices depends both on the extent to which customers would likely substitute away from the products in the candidate market in response to such a price increase and on the profit margins earned on those products. The profit margin on incremental units is the difference between price and incremental cost on those units. The Agencies often estimate incremental costs, for example using merging parties’ documents or data the merging parties use to make business decisions. Incremental cost is measured over the change in output that would be caused by the price increase under consideration.

In considering customers’ likely responses to higher prices, the Agencies take into account any reasonably available and reliable evidence, including, but not limited to:

- how customers have shifted purchases in the past in response to relative changes in price or other terms and conditions;
- information from buyers, including surveys, concerning how they would respond to price changes;
- the conduct of industry participants, notably:
  - sellers’ business decisions or business documents indicating sellers’ informed beliefs concerning how customers would substitute among products in response to relative changes in price;
  - industry participants’ behavior in tracking and responding to price changes by some or all rivals;
- objective information about product characteristics and the costs and delays of switching products, especially switching from products in the candidate market to products outside the candidate market;
- the percentage of sales lost by one product in the candidate market, when its price alone rises, that is recaptured by other products in the candidate market, with a higher recapture percentage making a price increase more profitable for the hypothetical monopolist;
- evidence from other industry participants, such as sellers of complementary products;
legal or regulatory requirements; and

the influence of downstream competition faced by customers in their output markets.

When the necessary data are available, the Agencies also may consider a “critical loss analysis” to assess the extent to which it corroborates inferences drawn from the evidence noted above. Critical loss analysis asks whether imposing at least a SSNIP on one or more products in a candidate market would raise or lower the hypothetical monopolist’s profits. While this “breakeven” analysis differs from the profit-maximizing analysis called for by the hypothetical monopolist test in Section 4.1.1, merging parties sometimes present this type of analysis to the Agencies. A price increase raises profits on sales made at the higher price, but this will be offset to the extent customers substitute away from products in the candidate market. Critical loss analysis compares the magnitude of these two offsetting effects resulting from the price increase. The “critical loss” is defined as the number of lost unit sales that would leave profits unchanged. The “predicted loss” is defined as the number of unit sales that the hypothetical monopolist is predicted to lose due to the price increase. The price increase raises the hypothetical monopolist’s profits if the predicted loss is less than the critical loss.

The Agencies consider all of the evidence of customer substitution noted above in assessing the predicted loss. The Agencies require that estimates of the predicted loss be consistent with that evidence, including the pre-merger margins of products in the candidate market used to calculate the critical loss. Unless the firms are engaging in coordinated interaction (see Section 7), high pre-merger margins normally indicate that each firm’s product individually faces demand that is not highly sensitive to price. Higher pre-merger margins thus indicate a smaller predicted loss as well as a smaller critical loss. The higher the pre-merger margin, the smaller the recapture percentage necessary for the candidate market to satisfy the hypothetical monopolist test.

Even when the evidence necessary to perform the hypothetical monopolist test quantitatively is not available, the conceptual framework of the test provides a useful methodological tool for gathering and analyzing evidence pertinent to customer substitution and to market definition. The Agencies follow the hypothetical monopolist test to the extent possible given the available evidence, bearing in mind that the ultimate goal of market definition is to help determine whether the merger may substantially lessen competition.

4.1.4 Product Market Definition with Targeted Customers

If a hypothetical monopolist could profitably target a subset of customers for price increases, the Agencies may identify relevant markets defined around those targeted customers, to whom a hypothetical monopolist would profitably and separately impose at least a SSNIP. Markets to serve targeted customers are also known as price discrimination markets. In practice, the Agencies identify price discrimination markets only where they believe there is a realistic prospect of an adverse competitive effect on a group of targeted customers.

Example 11: Glass containers have many uses. In response to a price increase for glass containers, some users would substitute substantially to plastic or metal containers, but baby food manufacturers would not. If a

6 While margins are important for implementing the hypothetical monopolist test, high margins are not in themselves of antitrust concern.
hypothetical monopolist could price separately and limit arbitrage, baby food manufacturers would be vulnerable to a targeted increase in the price of glass containers. The Agencies could define a distinct market for glass containers used to package baby food.

The Agencies also often consider markets for targeted customers when prices are individually negotiated and suppliers have information about customers that would allow a hypothetical monopolist to identify customers that are likely to pay a higher price for the relevant product. If prices are negotiated individually with customers, the hypothetical monopolist test may suggest relevant markets that are as narrow as individual customers (see also Section 6.2 on bargaining and auctions). Nonetheless, the Agencies often define markets for groups of targeted customers, i.e., by type of customer, rather than by individual customer. By so doing, the Agencies are able to rely on aggregated market shares that can be more helpful in predicting the competitive effects of the merger.

4.2 Geographic Market Definition

The arena of competition affected by the merger may be geographically bounded if geography limits some customers’ willingness or ability to substitute to some products, or some suppliers’ willingness or ability to serve some customers. Both supplier and customer locations can affect this. The Agencies apply the principles of market definition described here and in Section 4.1 to define a relevant market with a geographic dimension as well as a product dimension.

The scope of geographic markets often depends on transportation costs. Other factors such as language, regulation, tariff and non-tariff trade barriers, custom and familiarity, reputation, and service availability may impede long-distance or international transactions. The competitive significance of foreign firms may be assessed at various exchange rates, especially if exchange rates have fluctuated in the recent past.

In the absence of price discrimination based on customer location, the Agencies normally define geographic markets based on the locations of suppliers, as explained in subsection 4.2.1. In other cases, notably if price discrimination based on customer location is feasible as is often the case when delivered pricing is commonly used in the industry, the Agencies may define geographic markets based on the locations of customers, as explained in subsection 4.2.2.

4.2.1 Geographic Markets Based on the Locations of Suppliers

Geographic markets based on the locations of suppliers encompass the region from which sales are made. Geographic markets of this type often apply when customers receive goods or services at suppliers’ locations. Competitors in the market are firms with relevant production, sales, or service facilities in that region. Some customers who buy from these firms may be located outside the boundaries of the geographic market.

The hypothetical monopolist test requires that a hypothetical profit-maximizing firm that was the only present or future producer of the relevant product(s) located in the region would impose at least a SSNIP from at least one location, including at least one location of one of the merging firms. In this exercise the terms of sale for all products produced elsewhere are held constant. A single firm may operate in a number of different geographic markets, even for a single product.
Example 12: The merging parties both have manufacturing plants in City X. The relevant product is expensive to transport and suppliers price their products for pickup at their locations. Rival plants are some distance away in City Y. A hypothetical monopolist controlling all plants in City X could profitably impose a SSNIP at these plants. Competition from more distant plants would not defeat the price increase because supplies coming from more distant plants require expensive transportation. The relevant geographic market is defined around the plants in City X.

When the geographic market is defined based on supplier locations, sales made by suppliers located in the geographic market are counted, regardless of the location of the customer making the purchase.

In considering likely reactions of customers to price increases for the relevant product(s) imposed in a candidate geographic market, the Agencies consider any reasonably available and reliable evidence, including:

- how customers have shifted purchases in the past between different geographic locations in response to relative changes in price or other terms and conditions;
- the cost and difficulty of transporting the product (or the cost and difficulty of a customer traveling to a seller’s location), in relation to its price;
- whether suppliers need a presence near customers to provide service or support;
- evidence on whether sellers base business decisions on the prospect of customers switching between geographic locations in response to relative changes in price or other competitive variables;
- the costs and delays of switching from suppliers in the candidate geographic market to suppliers outside the candidate geographic market; and
- the influence of downstream competition faced by customers in their output markets.

4.2.2 Geographic Markets Based on the Locations of Customers

When the hypothetical monopolist could discriminate based on customer location, the Agencies may define geographic markets based on the locations of targeted customers.\(^7\) Geographic markets of this type often apply when suppliers deliver their products or services to customers’ locations. Geographic markets of this type encompass the region into which sales are made. Competitors in the market are firms that sell to customers in the specified region. Some suppliers that sell into the relevant market may be located outside the boundaries of the geographic market.

The hypothetical monopolist test requires that a hypothetical profit-maximizing firm that was the only present or future seller of the relevant product(s) to customers in the region would impose at least a SSNIP on some customers in that region. A region forms a relevant geographic market if this price increase would not be defeated by substitution away from the relevant product or by arbitrage.

\(^7\) For customers operating in multiple locations, only those customer locations within the targeted zone are included in the market.
e.g., customers in the region travelling outside it to purchase the relevant product. In this exercise, the terms of sale for products sold to all customers outside the region are held constant.

*Example 13:* Customers require local sales and support. Suppliers have sales and service operations in many geographic areas and can discriminate based on customer location. The geographic market can be defined around the locations of customers.

*Example 14:* Each merging firm has a single manufacturing plant and delivers the relevant product to customers in City X and in City Y. The relevant product is expensive to transport. The merging firms’ plants are by far the closest to City X, but no closer to City Y than are numerous rival plants. This fact pattern suggests that customers in City X may be harmed by the merger even if customers in City Y are not. For that reason, the Agencies consider a relevant geographic market defined around customers in City X. Such a market could be defined even if the region around the merging firms’ plants would not be a relevant geographic market defined based on the location of sellers because a hypothetical monopolist controlling all plants in that region would find a SSNIP imposed on all of its customers unprofitable due to the loss of sales to customers in City Y.

When the geographic market is defined based on customer locations, sales made to those customers are counted, regardless of the location of the supplier making those sales.

*Example 15:* Customers in the United States must use products approved by U.S. regulators. Foreign customers use products not approved by U.S. regulators. The relevant product market consists of products approved by U.S. regulators. The geographic market is defined around U.S. customers. Any sales made to U.S. customers by foreign suppliers are included in the market, and those foreign suppliers are participants in the U.S. market even though located outside it.

5. **Market Participants, Market Shares, and Market Concentration**

The Agencies normally consider measures of market shares and market concentration as part of their evaluation of competitive effects. The Agencies evaluate market shares and concentration in conjunction with other reasonably available and reliable evidence for the ultimate purpose of determining whether a merger may substantially lessen competition.

Market shares can directly influence firms’ competitive incentives. For example, if a price reduction to gain new customers would also apply to a firm’s existing customers, a firm with a large market share may be more reluctant to implement a price reduction than one with a small share. Likewise, a firm with a large market share may not feel pressure to reduce price even if a smaller rival does. Market shares also can reflect firms’ capabilities. For example, a firm with a large market share may be able to expand output rapidly by a larger absolute amount than can a small firm. Similarly, a large market share tends to indicate low costs, an attractive product, or both.

5.1 **Market Participants**

All firms that currently earn revenues in the relevant market are considered market participants. Vertically integrated firms are also included to the extent that their inclusion accurately reflects their competitive significance. Firms not currently earning revenues in the relevant market, but that have committed to entering the market in the near future, are also considered market participants.

Firms that are not current producers in a relevant market, but that would very likely provide rapid supply responses with direct competitive impact in the event of a SSNIP, without incurring
significant sunk costs, are also considered market participants. These firms are termed “rapid entrants.” Sunk costs are entry or exit costs that cannot be recovered outside the relevant market. Entry that would take place more slowly in response to adverse competitive effects, or that requires firms to incur significant sunk costs, is considered in Section 9.

Firms that produce the relevant product but do not sell it in the relevant geographic market may be rapid entrants. Other things equal, such firms are most likely to be rapid entrants if they are close to the geographic market.

Example 16: Farm A grows tomatoes halfway between Cities X and Y. Currently, it ships its tomatoes to City X because prices there are two percent higher. Previously it has varied the destination of its shipments in response to small price variations. Farm A would likely be a rapid entrant participant in a market for tomatoes in City Y.

Example 17: Firm B has bid multiple times to supply milk to School District S, and actually supplies milk to schools in some adjacent areas. It has never won a bid in School District S, but is well qualified to serve that district and has often nearly won. Firm B would be counted as a rapid entrant in a market for school milk in School District S.

More generally, if the relevant market is defined around targeted customers, firms that produce relevant products but do not sell them to those customers may be rapid entrants if they can easily and rapidly begin selling to the targeted customers.

Firms that clearly possess the necessary assets to supply into the relevant market rapidly may also be rapid entrants. In markets for relatively homogeneous goods where a supplier’s ability to compete depends predominantly on its costs and its capacity, and not on other factors such as experience or reputation in the relevant market, a supplier with efficient idle capacity, or readily available “swing” capacity currently used in adjacent markets that can easily and profitably be shifted to serve the relevant market, may be a rapid entrant. However, idle capacity may be inefficient, and capacity used in adjacent markets may not be available, so a firm’s possession of idle or swing capacity alone does not make that firm a rapid entrant.

5.2 Market Shares

The Agencies normally calculate market shares for all firms that currently produce products in the relevant market, subject to the availability of data. The Agencies also calculate market shares for other market participants if this can be done to reliably reflect their competitive significance.

Market concentration and market share data are normally based on historical evidence. However, recent or ongoing changes in market conditions may indicate that the current market share of a particular firm either understates or overstates the firm’s future competitive significance. The Agencies consider reasonably predictable effects of recent or ongoing changes in market conditions when calculating and interpreting market share data. For example, if a new technology that is important to long-term competitive viability is available to other firms in the market, but is not available to a particular firm, the Agencies may conclude that that firm’s historical market share

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8 If this type of supply side substitution is nearly universal among the firms selling one or more of a group of products, the Agencies may use an aggregate description of markets for those products as a matter of convenience.
overstates its future competitive significance. The Agencies may project historical market shares into the foreseeable future when this can be done reliably.

The Agencies measure market shares based on the best available indicator of firms’ future competitive significance in the relevant market. This may depend upon the type of competitive effect being considered, and on the availability of data. Typically, annual data are used, but where individual transactions are large and infrequent so annual data may be unrepresentative, the Agencies may measure market shares over a longer period of time.

In most contexts, the Agencies measure each firm’s market share based on its actual or projected revenues in the relevant market. Revenues in the relevant market tend to be the best measure of attractiveness to customers, since they reflect the real-world ability of firms to surmount all of the obstacles necessary to offer products on terms and conditions that are attractive to customers. In cases where one unit of a low-priced product can substitute for one unit of a higher-priced product, unit sales may measure competitive significance better than revenues. For example, a new, much less expensive product may have great competitive significance if it substantially erodes the revenues earned by older, higher-priced products, even if it earns relatively few revenues. In cases where customers sign long-term contracts, face switching costs, or tend to re-evaluate their suppliers only occasionally, revenues earned from recently acquired customers may better reflect the competitive significance of suppliers than do total revenues.

In markets for homogeneous products, a firm’s competitive significance may derive principally from its ability and incentive to rapidly expand production in the relevant market in response to a price increase or output reduction by others in that market. As a result, a firm’s competitive significance may depend upon its level of readily available capacity to serve the relevant market if that capacity is efficient enough to make such expansion profitable. In such markets, capacities or reserves may better reflect the future competitive significance of suppliers than revenues, and the Agencies may calculate market shares using those measures. Market participants that are not current producers may then be assigned positive market shares, but only if a measure of their competitive significance properly comparable to that of current producers is available. When market shares are measured based on firms’ readily available capacities, the Agencies do not include capacity that is committed or so profitably employed outside the relevant market, or so high-cost, that it would not likely be used to respond to a SSNIP in the relevant market.

*Example 18:* The geographic market is defined around customers in the United States. Firm X produces the relevant product outside the United States, and most of its sales are made to customers outside the United States. In most contexts, Firm X’s market share will be based on its sales to U.S. customers, not its total sales or total capacity. However, if the relevant product is homogeneous, and if Firm X would significantly expand sales to U.S. customers rapidly and without incurring significant sunk costs in response to a SSNIP, the Agencies may base Firm X’s market share on its readily available capacity to serve U.S. customers.

When the Agencies define markets serving targeted customers, these same principles are used to measure market shares, as they apply to those customers. In most contexts, each firm’s market share is based on its actual or projected revenues from the targeted customers. However, the Agencies may instead measure market shares based on revenues from a broader group of customers if doing so would more accurately reflect the competitive significance of different suppliers in the relevant market. Revenues earned from a broader group of customers may also be used when better data are thereby available.
5.3 Market Concentration

Market concentration is often one useful indicator of likely competitive effects of a merger. In evaluating market concentration, the Agencies consider both the post-merger level of market concentration and the change in concentration resulting from a merger. Market shares may not fully reflect the competitive significance of firms in the market or the impact of a merger. They are used in conjunction with other evidence of competitive effects. See Sections 6 and 7.

In analyzing mergers between an incumbent and a recent or potential entrant, to the extent the Agencies use the change in concentration to evaluate competitive effects, they will do so using projected market shares. A merger between an incumbent and a potential entrant can raise significant competitive concerns. The lessening of competition resulting from such a merger is more likely to be substantial, the larger is the market share of the incumbent, the greater is the competitive significance of the potential entrant, and the greater is the competitive threat posed by this potential entrant relative to others.

The Agencies give more weight to market concentration when market shares have been stable over time, especially in the face of historical changes in relative prices or costs. If a firm has retained its market share even after its price has increased relative to those of its rivals, that firm already faces limited competitive constraints, making it less likely that its remaining rivals will replace the competition lost if one of that firm’s important rivals is eliminated due to a merger. By contrast, even a highly concentrated market can be very competitive if market shares fluctuate substantially over short periods of time in response to changes in competitive offerings. However, if competition by one of the merging firms has significantly contributed to these fluctuations, perhaps because it has acted as a maverick, the Agencies will consider whether the merger will enhance market power by combining that firm with one of its significant rivals.

The Agencies may measure market concentration using the number of significant competitors in the market. This measure is most useful when there is a gap in market share between significant competitors and smaller rivals or when it is difficult to measure revenues in the relevant market. The Agencies also may consider the combined market share of the merging firms as an indicator of the extent to which others in the market may not be able readily to replace competition between the merging firms that is lost through the merger.

The Agencies often calculate the Herfindahl-Hirschman Index ("HHI") of market concentration. The HHI is calculated by summing the squares of the individual firms’ market shares, and thus gives proportionately greater weight to the larger market shares. When using the HHI, the Agencies

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9 For example, a market consisting of four firms with market shares of thirty percent, thirty percent, twenty percent, and twenty percent has an HHI of 2600 \((30^2 + 30^2 + 20^2 + 20^2 = 2600)\). The HHI ranges from 10,000 (in the case of a pure monopoly) to a number approaching zero (in the case of an atomistic market). Although it is desirable to include all firms in the calculation, lack of information about firms with small shares is not critical because such firms do not affect the HHI significantly.
consider both the post-merger level of the HHI and the increase in the HHI resulting from the merger. The increase in the HHI is equal to twice the product of the market shares of the merging firms.\(^{10}\)

Based on their experience, the Agencies generally classify markets into three types:

- **Unconcentrated Markets:** HHI below 1500
- **Moderately Concentrated Markets:** HHI between 1500 and 2500
- **Highly Concentrated Markets:** HHI above 2500

The Agencies employ the following general standards for the relevant markets they have defined:

- **Small Change in Concentration:** Mergers involving an increase in the HHI of less than 100 points are unlikely to have adverse competitive effects and ordinarily require no further analysis.

- **Unconcentrated Markets:** Mergers resulting in unconcentrated markets are unlikely to have adverse competitive effects and ordinarily require no further analysis.

- **Moderately Concentrated Markets:** Mergers resulting in moderately concentrated markets that involve an increase in the HHI of more than 100 points potentially raise significant competitive concerns and often warrant scrutiny.

- **Highly Concentrated Markets:** Mergers resulting in highly concentrated markets that involve an increase in the HHI of between 100 points and 200 points potentially raise significant competitive concerns and often warrant scrutiny. Mergers resulting in highly concentrated markets that involve an increase in the HHI of more than 200 points will be presumed to be likely to enhance market power. The presumption may be rebutted by persuasive evidence showing that the merger is unlikely to enhance market power.

The purpose of these thresholds is not to provide a rigid screen to separate competitively benign mergers from anticompetitive ones, although high levels of concentration do raise concerns. Rather, they provide one way to identify some mergers unlikely to raise competitive concerns and some others for which it is particularly important to examine whether other competitive factors confirm, reinforce, or counteract the potentially harmful effects of increased concentration. The higher the post-merger HHI and the increase in the HHI, the greater are the Agencies’ potential competitive concerns and the greater is the likelihood that the Agencies will request additional information to conduct their analysis.

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\(^{10}\) For example, the merger of firms with shares of five percent and ten percent of the market would increase the HHI by 100 \((5 \times 10 \times 2 = 100)\).
6. Unilateral Effects

The elimination of competition between two firms that results from their merger may alone constitute a substantial lessening of competition. Such unilateral effects are most apparent in a merger to monopoly in a relevant market, but are by no means limited to that case. Whether cognizable efficiencies resulting from the merger are likely to reduce or reverse adverse unilateral effects is addressed in Section 10.

Several common types of unilateral effects are discussed in this section. Section 6.1 discusses unilateral price effects in markets with differentiated products. Section 6.2 discusses unilateral effects in markets where sellers negotiate with buyers or prices are determined through auctions. Section 6.3 discusses unilateral effects relating to reductions in output or capacity in markets for relatively homogeneous products. Section 6.4 discusses unilateral effects arising from diminished innovation or reduced product variety. These effects do not exhaust the types of possible unilateral effects; for example, exclusionary unilateral effects also can arise.

A merger may result in different unilateral effects along different dimensions of competition. For example, a merger may increase prices in the short term but not raise longer-term concerns about innovation, either because rivals will provide sufficient innovation competition or because the merger will generate cognizable research and development efficiencies. See Section 10.

6.1 Pricing of Differentiated Products

In differentiated product industries, some products can be very close substitutes and compete strongly with each other, while other products are more distant substitutes and compete less strongly. For example, one high-end product may compete much more directly with another high-end product than with any low-end product.

A merger between firms selling differentiated products may diminish competition by enabling the merged firm to profit by unilaterally raising the price of one or both products above the pre-merger level. Some of the sales lost due to the price rise will merely be diverted to the product of the merger partner and, depending on relative margins, capturing such sales loss through merger may make the price increase profitable even though it would not have been profitable prior to the merger.

The extent of direct competition between the products sold by the merging parties is central to the evaluation of unilateral price effects. Unilateral price effects are greater, the more the buyers of products sold by one merging firm consider products sold by the other merging firm to be their next choice. The Agencies consider any reasonably available and reliable information to evaluate the extent of direct competition between the products sold by the merging firms. This includes documentary and testimonial evidence, win/loss reports and evidence from discount approval processes, customer switching patterns, and customer surveys. The types of evidence relied on often overlap substantially with the types of evidence of customer substitution relevant to the hypothetical monopolist test. See Section 4.1.1.

Substantial unilateral price elevation post-merger for a product formerly sold by one of the merging firms normally requires that a significant fraction of the customers purchasing that product view
products formerly sold by the other merging firm as their next-best choice. However, unless pre-merger margins between price and incremental cost are low, that significant fraction need not approach a majority. For this purpose, incremental cost is measured over the change in output that would be caused by the price change considered. A merger may produce significant unilateral effects for a given product even though many more sales are diverted to products sold by non-merging firms than to products previously sold by the merger partner.

Example 19: In Example 5, the merged entity controlling Products A and B would raise prices ten percent, given the product offerings and prices of other firms. In that example, one-third of the sales lost by Product A when its price alone is raised are diverted to Product B. Further analysis is required to account for repositioning, entry, and efficiencies.

In some cases, the Agencies may seek to quantify the extent of direct competition between a product sold by one merging firm and a second product sold by the other merging firm by estimating the diversion ratio from the first product to the second product. The diversion ratio is the fraction of unit sales lost by the first product due to an increase in its price that would be diverted to the second product. Diversion ratios between products sold by one merging firm and products sold by the other merging firm can be very informative for assessing unilateral price effects, with higher diversion ratios indicating a greater likelihood of such effects. Diversion ratios between products sold by merging firms and those sold by non-merging firms have at most secondary predictive value.

Adverse unilateral price effects can arise when the merger gives the merged entity an incentive to raise the price of a product previously sold by one merging firm and thereby divert sales to products previously sold by the other merging firm, boosting the profits on the latter products. Taking as given other prices and product offerings, that boost to profits is equal to the value to the merged firm of the sales diverted to those products. The value of sales diverted to a product is equal to the number of units diverted to that product multiplied by the margin between price and incremental cost on that product. In some cases, where sufficient information is available, the Agencies assess the value of diverted sales, which can serve as an indicator of the upward pricing pressure on the first product resulting from the merger. Diagnosing unilateral price effects based on the value of diverted sales need not rely on market definition or the calculation of market shares and concentration. The Agencies rely much more on the value of diverted sales than on the level of the HHI for diagnosing unilateral price effects in markets with differentiated products. If the value of diverted sales is proportionately small, significant unilateral price effects are unlikely.\footnote{For this purpose, the value of diverted sales is measured in proportion to the lost revenues attributable to the reduction in unit sales resulting from the price increase. Those lost revenues equal the reduction in the number of units sold of that product multiplied by that product’s price.}

Where sufficient data are available, the Agencies may construct economic models designed to quantify the unilateral price effects resulting from the merger. These models often include independent price responses by non-merging firms. They also can incorporate merger-specific efficiencies. These merger simulation methods need not rely on market definition. The Agencies do not treat merger simulation evidence as conclusive in itself, and they place more weight on whether their merger simulations consistently predict substantial price increases than on the precise prediction of any single simulation.

\footnote{For this purpose, the value of diverted sales is measured in proportion to the lost revenues attributable to the reduction in unit sales resulting from the price increase. Those lost revenues equal the reduction in the number of units sold of that product multiplied by that product’s price.}
A merger is unlikely to generate substantial unilateral price increases if non-merging parties offer very close substitutes for the products offered by the merging firms. In some cases, non-merging firms may be able to reposition their products to offer close substitutes for the products offered by the merging firms. Repositioning is a supply-side response that is evaluated much like entry, with consideration given to timeliness, likelihood, and sufficiency. See Section 9. The Agencies consider whether repositioning would be sufficient to deter or counteract what otherwise would be significant anticompetitive unilateral effects from a differentiated products merger.

6.2 Bargaining and Auctions

In many industries, especially those involving intermediate goods and services, buyers and sellers negotiate to determine prices and other terms of trade. In that process, buyers commonly negotiate with more than one seller, and may play sellers off against one another. Some highly structured forms of such competition are known as auctions. Negotiations often combine aspects of an auction with aspects of one-on-one negotiation, although pure auctions are sometimes used in government procurement and elsewhere.

A merger between two competing sellers prevents buyers from playing those sellers off against each other in negotiations. This alone can significantly enhance the ability and incentive of the merged entity to obtain a result more favorable to it, and less favorable to the buyer, than the merging firms would have offered separately absent the merger. The Agencies analyze unilateral effects of this type using similar approaches to those described in Section 6.1.

Anticompetitive unilateral effects in these settings are likely in proportion to the frequency or probability with which, prior to the merger, one of the merging sellers had been the runner-up when the other won the business. These effects also are likely to be greater, the greater advantage the runner-up merging firm has over other suppliers in meeting customers’ needs. These effects also tend to be greater, the more profitable were the pre-merger winning bids. All of these factors are likely to be small if there are many equally placed bidders.

The mechanisms of these anticompetitive unilateral effects, and the indicia of their likelihood, differ somewhat according to the bargaining practices used, the auction format, and the sellers’ information about one another’s costs and about buyers’ preferences. For example, when the merging sellers are likely to know which buyers they are best and second best placed to serve, any anticompetitive unilateral effects are apt to be targeted at those buyers; when sellers are less well informed, such effects are more apt to be spread over a broader class of buyers.

6.3 Capacity and Output for Homogeneous Products

In markets involving relatively undifferentiated products, the Agencies may evaluate whether the merged firm will find it profitable unilaterally to suppress output and elevate the market price. A firm may leave capacity idle, refrain from building or obtaining capacity that would have been obtained absent the merger, or eliminate pre-existing production capabilities. A firm may also divert the use of capacity away from one relevant market and into another so as to raise the price in the former market. The competitive analyses of these alternative modes of output suppression may differ.
A unilateral output suppression strategy is more likely to be profitable when (1) the merged firm’s market share is relatively high; (2) the share of the merged firm’s output already committed for sale at prices unaffected by the output suppression is relatively low; (3) the margin on the suppressed output is relatively low; (4) the supply responses of rivals are relatively small; and (5) the market elasticity of demand is relatively low.

A merger may provide the merged firm a larger base of sales on which to benefit from the resulting price rise, or it may eliminate a competitor that otherwise could have expanded its output in response to the price rise.

Example 20: Firms A and B both produce an industrial commodity and propose to merge. The demand for this commodity is insensitive to price. Firm A is the market leader. Firm B produces substantial output, but its operating margins are low because it operates high-cost plants. The other suppliers are operating very near capacity. The merged firm has an incentive to reduce output at the high-cost plants, perhaps shutting down some of that capacity, thus driving up the price it receives on the remainder of its output. The merger harms customers, notwithstanding that the merged firm shifts some output from high-cost plants to low-cost plants.

In some cases, a merger between a firm with a substantial share of the sales in the market and a firm with significant excess capacity to serve that market can make an output suppression strategy profitable.\(^\text{12}\) This can occur even if the firm with the excess capacity has a relatively small share of sales, if that firm’s ability to expand, and thus keep price from rising, has been making an output suppression strategy unprofitable for the firm with the larger market share.

### 6.4 Innovation and Product Variety

Competition often spurs firms to innovate. The Agencies may consider whether a merger is likely to diminish innovation competition by encouraging the merged firm to curtail its innovative efforts below the level that would prevail in the absence of the merger. That curtailment of innovation could take the form of reduced incentive to continue with an existing product-development effort or reduced incentive to initiate development of new products.

The first of these effects is most likely to occur if at least one of the merging firms is engaging in efforts to introduce new products that would capture substantial revenues from the other merging firm. The second, longer-run effect is most likely to occur if at least one of the merging firms has capabilities that are likely to lead it to develop new products in the future that would capture substantial revenues from the other merging firm. The Agencies therefore also consider whether a merger will diminish innovation competition by combining two of a very small number of firms with the strongest capabilities to successfully innovate in a specific direction.

The Agencies evaluate the extent to which successful innovation by one merging firm is likely to take sales from the other, and the extent to which post-merger incentives for future innovation will be lower than those that would prevail in the absence of the merger. The Agencies also consider whether the merger is likely to enable innovation that would not otherwise take place, by bringing together

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\(^{12}\) Such a merger also can cause adverse coordinated effects, especially if the acquired firm with excess capacity was disrupting effective coordination.
complementary capabilities that cannot be otherwise combined or for some other merger-specific reason. See Section 10.

The Agencies also consider whether a merger is likely to give the merged firm an incentive to cease offering one of the relevant products sold by the merging parties. Reductions in variety following a merger may or may not be anticompetitive. Mergers can lead to the efficient consolidation of products when variety offers little in value to customers. In other cases, a merger may increase variety by encouraging the merged firm to reposition its products to be more differentiated from one another.

If the merged firm would withdraw a product that a significant number of customers strongly prefer to those products that would remain available, this can constitute a harm to customers over and above any effects on the price or quality of any given product. If there is evidence of such an effect, the Agencies may inquire whether the reduction in variety is largely due to a loss of competitive incentives attributable to the merger. An anticompetitive incentive to eliminate a product as a result of the merger is greater and more likely, the larger is the share of profits from that product coming at the expense of profits from products sold by the merger partner. Where a merger substantially reduces competition by bringing two close substitute products under common ownership, and one of those products is eliminated, the merger will often also lead to a price increase on the remaining product, but that is not a necessary condition for anticompetitive effect.

Example 21: Firm A sells a high-end product at a premium price. Firm B sells a mid-range product at a lower price, serving customers who are more price sensitive. Several other firms have low-end products. Firms A and B together have a large share of the relevant market. Firm A proposes to acquire Firm B and discontinue Firm B’s product. Firm A expects to retain most of Firm B’s customers. Firm A may not find it profitable to raise the price of its high-end product after the merger, because doing so would reduce its ability to retain Firm B’s more price-sensitive customers. The Agencies may conclude that the withdrawal of Firm B’s product results from a loss of competition and materially harms customers.

7. Coordinated Effects

A merger may diminish competition by enabling or encouraging post-merger coordinated interaction among firms in the relevant market that harms customers. Coordinated interaction involves conduct by multiple firms that is profitable for each of them only as a result of the accommodating reactions of the others. These reactions can blunt a firm’s incentive to offer customers better deals by undercutting the extent to which such a move would win business away from rivals. They also can enhance a firm’s incentive to raise prices, by assuaging the fear that such a move would lose customers to rivals.

Coordinated interaction includes a range of conduct. Coordinated interaction can involve the explicit negotiation of a common understanding of how firms will compete or refrain from competing. Such conduct typically would itself violate the antitrust laws. Coordinated interaction also can involve a similar common understanding that is not explicitly negotiated but would be enforced by the detection and punishment of deviations that would undermine the coordinated interaction. Coordinated interaction alternatively can involve parallel accommodating conduct not pursuant to a prior understanding. Parallel accommodating conduct includes situations in which each rival’s response to competitive moves made by others is individually rational, and not motivated by
retaliation or deterrence nor intended to sustain an agreed-upon market outcome, but nevertheless emboldens price increases and weakens competitive incentives to reduce prices or offer customers better terms. Coordinated interaction includes conduct not otherwise condemned by the antitrust laws.

The ability of rival firms to engage in coordinated conduct depends on the strength and predictability of rivals’ responses to a price change or other competitive initiative. Under some circumstances, a merger can result in market concentration sufficient to strengthen such responses or enable multiple firms in the market to predict them more confidently, thereby affecting the competitive incentives of multiple firms in the market, not just the merged firm.

### 7.1 Impact of Merger on Coordinated Interaction

The Agencies examine whether a merger is likely to change the manner in which market participants interact, inducing substantially more coordinated interaction. The Agencies seek to identify how a merger might significantly weaken competitive incentives through an increase in the strength, extent, or likelihood of coordinated conduct. There are, however, numerous forms of coordination, and the risk that a merger will induce adverse coordinated effects may not be susceptible to quantification or detailed proof. Therefore, the Agencies evaluate the risk of coordinated effects using measures of market concentration (see Section 5) in conjunction with an assessment of whether a market is vulnerable to coordinated conduct. See Section 7.2. The analysis in Section 7.2 applies to moderately and highly concentrated markets, as unconcentrated markets are unlikely to be vulnerable to coordinated conduct.

Pursuant to the Clayton Act’s incipiency standard, the Agencies may challenge mergers that in their judgment pose a real danger of harm through coordinated effects, even without specific evidence showing precisely how the coordination likely would take place. The Agencies are likely to challenge a merger if the following three conditions are all met: (1) the merger would significantly increase concentration and lead to a moderately or highly concentrated market; (2) that market shows signs of vulnerability to coordinated conduct (see Section 7.2); and (3) the Agencies have a credible basis on which to conclude that the merger may enhance that vulnerability. An acquisition eliminating a maverick firm (see Section 2.1.5) in a market vulnerable to coordinated conduct is likely to cause adverse coordinated effects.

### 7.2 Evidence a Market is Vulnerable to Coordinated Conduct

The Agencies presume that market conditions are conducive to coordinated interaction if firms representing a substantial share in the relevant market appear to have previously engaged in express collusion affecting the relevant market, unless competitive conditions in the market have since changed significantly. Previous express collusion in another geographic market will have the same weight if the salient characteristics of that other market at the time of the collusion are comparable to those in the relevant market. Failed previous attempts at collusion in the relevant market suggest that successful collusion was difficult pre-merger but not so difficult as to deter attempts, and a merger may tend to make success more likely. Previous collusion or attempted collusion in another product market may also be given substantial weight if the salient characteristics of that other market at the time of the collusion are closely comparable to those in the relevant market.
A market typically is more vulnerable to coordinated conduct if each competitively important firm’s significant competitive initiatives can be promptly and confidently observed by that firm’s rivals. This is more likely to be the case if the terms offered to customers are relatively transparent. Price transparency can be greater for relatively homogeneous products. Even if terms of dealing are not transparent, transparency regarding the identities of the firms serving particular customers can give rise to coordination, e.g., through customer or territorial allocation. Regular monitoring by suppliers of one another’s prices or customers can indicate that the terms offered to customers are relatively transparent.

A market typically is more vulnerable to coordinated conduct if a firm’s prospective competitive reward from attracting customers away from its rivals will be significantly diminished by likely responses of those rivals. This is more likely to be the case, the stronger and faster are the responses the firm anticipates from its rivals. The firm is more likely to anticipate strong responses if there are few significant competitors, if products in the relevant market are relatively homogeneous, if customers find it relatively easy to switch between suppliers, or if suppliers use meeting-competition clauses.

A firm is more likely to be deterred from making competitive initiatives by whatever responses occur if sales are small and frequent rather than via occasional large and long-term contracts or if relatively few customers will switch to it before rivals are able to respond. A firm is less likely to be deterred by whatever responses occur if the firm has little stake in the status quo. For example, a firm with a small market share that can quickly and dramatically expand, constrained neither by limits on production nor by customer reluctance to switch providers or to entrust business to a historically small provider, is unlikely to be deterred. Firms are also less likely to be deterred by whatever responses occur if competition in the relevant market is marked by leapfrogging technological innovation, so that responses by competitors leave the gains from successful innovation largely intact.

A market is more apt to be vulnerable to coordinated conduct if the firm initiating a price increase will lose relatively few customers after rivals respond to the increase. Similarly, a market is more apt to be vulnerable to coordinated conduct if a firm that first offers a lower price or improved product to customers will retain relatively few customers thus attracted away from its rivals after those rivals respond.

The Agencies regard coordinated interaction as more likely, the more the participants stand to gain from successful coordination. Coordination generally is more profitable, the lower is the market elasticity of demand.

Coordinated conduct can harm customers even if not all firms in the relevant market engage in the coordination, but significant harm normally is likely only if a substantial part of the market is subject to such conduct. The prospect of harm depends on the collective market power, in the relevant market, of firms whose incentives to compete are substantially weakened by coordinated conduct. This collective market power is greater, the lower is the market elasticity of demand. This collective market power is diminished by the presence of other market participants with small market shares and little stake in the outcome resulting from the coordinated conduct, if these firms can rapidly expand their sales in the relevant market.
Buyer characteristics and the nature of the procurement process can affect coordination. For example, sellers may have the incentive to bid aggressively for a large contract even if they expect strong responses by rivals. This is especially the case for sellers with small market shares, if they can realistically win such large contracts. In some cases, a large buyer may be able to strategically undermine coordinated conduct, at least as it pertains to that buyer’s needs, by choosing to put up for bid a few large contracts rather than many smaller ones, and by making its procurement decisions opaque to suppliers.

8. Powerful Buyers

Powerful buyers are often able to negotiate favorable terms with their suppliers. Such terms may reflect the lower costs of serving these buyers, but they also can reflect price discrimination in their favor.

The Agencies consider the possibility that powerful buyers may constrain the ability of the merging parties to raise prices. This can occur, for example, if powerful buyers have the ability and incentive to vertically integrate upstream or sponsor entry, or if the conduct or presence of large buyers undermines coordinated effects. However, the Agencies do not presume that the presence of powerful buyers alone forestalls adverse competitive effects flowing from the merger. Even buyers that can negotiate favorable terms may be harmed by an increase in market power. The Agencies examine the choices available to powerful buyers and how those choices likely would change due to the merger. Normally, a merger that eliminates a supplier whose presence contributed significantly to a buyer’s negotiating leverage will harm that buyer.

Example 22: Customer C has been able to negotiate lower pre-merger prices than other customers by threatening to shift its large volume of purchases from one merging firm to the other. No other suppliers are as well placed to meet Customer C’s needs for volume and reliability. The merger is likely to harm Customer C. In this situation, the Agencies could identify a price discrimination market consisting of Customer C and similarly placed customers. The merger threatens to end previous price discrimination in their favor.

Furthermore, even if some powerful buyers could protect themselves, the Agencies also consider whether market power can be exercised against other buyers.

Example 23: In Example 22, if Customer C instead obtained the lower pre-merger prices based on a credible threat to supply its own needs, or to sponsor new entry, Customer C might not be harmed. However, even in this case, other customers may still be harmed.

9. Entry

The analysis of competitive effects in Sections 6 and 7 focuses on current participants in the relevant market. That analysis may also include some forms of entry. Firms that would rapidly and easily enter the market in response to a SSNIP are market participants and may be assigned market shares. See Sections 5.1 and 5.2. Firms that have, prior to the merger, committed to entering the market also will normally be treated as market participants. See Section 5.1. This section concerns entry or adjustments to pre-existing entry plans that are induced by the merger.
As part of their full assessment of competitive effects, the Agencies consider entry into the relevant market. The prospect of entry into the relevant market will alleviate concerns about adverse competitive effects only if such entry will deter or counteract any competitive effects of concern so the merger will not substantially harm customers.

The Agencies consider the actual history of entry into the relevant market and give substantial weight to this evidence. Lack of successful and effective entry in the face of non-transitory increases in the margins earned on products in the relevant market tends to suggest that successful entry is slow or difficult. Market values of incumbent firms greatly exceeding the replacement costs of their tangible assets may indicate that these firms have valuable intangible assets, which may be difficult or time consuming for an entrant to replicate.

A merger is not likely to enhance market power if entry into the market is so easy that the merged firm and its remaining rivals in the market, either unilaterally or collectively, could not profitably raise price or otherwise reduce competition compared to the level that would prevail in the absence of the merger. Entry is that easy if entry would be timely, likely, and sufficient in its magnitude, character, and scope to deter or counteract the competitive effects of concern.

The Agencies examine the timeliness, likelihood, and sufficiency of the entry efforts an entrant might practically employ. An entry effort is defined by the actions the firm must undertake to produce and sell in the market. Various elements of the entry effort will be considered. These elements can include: planning, design, and management; permitting, licensing, or other approvals; construction, debugging, and operation of production facilities; and promotion (including necessary introductory discounts), marketing, distribution, and satisfaction of customer testing and qualification requirements. Recent examples of entry, whether successful or unsuccessful, generally provide the starting point for identifying the elements of practical entry efforts. They also can be informative regarding the scale necessary for an entrant to be successful, the presence or absence of entry barriers, the factors that influence the timing of entry, the costs and risk associated with entry, and the sales opportunities realistically available to entrants.

If the assets necessary for an effective and profitable entry effort are widely available, the Agencies will not necessarily attempt to identify which firms might enter. Where an identifiable set of firms appears to have necessary assets that others lack, or to have particularly strong incentives to enter, the Agencies focus their entry analysis on those firms. Firms operating in adjacent or complementary markets, or large customers themselves, may be best placed to enter. However, the Agencies will not presume that a powerful firm in an adjacent market or a large customer will enter the relevant market unless there is reliable evidence supporting that conclusion.

In assessing whether entry will be timely, likely, and sufficient, the Agencies recognize that precise and detailed information may be difficult or impossible to obtain. The Agencies consider reasonably available and reliable evidence bearing on whether entry will satisfy the conditions of timeliness, likelihood, and sufficiency.
9.1 Timeliness

In order to deter the competitive effects of concern, entry must be rapid enough to make unprofitable overall the actions causing those effects and thus leading to entry, even though those actions would be profitable until entry takes effect.

Even if the prospect of entry does not deter the competitive effects of concern, post-merger entry may counteract them. This requires that the impact of entrants in the relevant market be rapid enough that customers are not significantly harmed by the merger, despite any anticompetitive harm that occurs prior to the entry.

The Agencies will not presume that an entrant can have a significant impact on prices before that entrant is ready to provide the relevant product to customers unless there is reliable evidence that anticipated future entry would have such an effect on prices.

9.2 Likelihood

Entry is likely if it would be profitable, accounting for the assets, capabilities, and capital needed and the risks involved, including the need for the entrant to incur costs that would not be recovered if the entrant later exits. Profitability depends upon (a) the output level the entrant is likely to obtain, accounting for the obstacles facing new entrants; (b) the price the entrant would likely obtain in the post-merger market, accounting for the impact of that entry itself on prices; and (c) the cost per unit the entrant would likely incur, which may depend upon the scale at which the entrant would operate.

9.3 Sufficiency

Even where timely and likely, entry may not be sufficient to deter or counteract the competitive effects of concern. For example, in a differentiated product industry, entry may be insufficient because the products offered by entrants are not close enough substitutes to the products offered by the merged firm to render a price increase by the merged firm unprofitable. Entry may also be insufficient due to constraints that limit entrants’ competitive effectiveness, such as limitations on the capabilities of the firms best placed to enter or reputational barriers to rapid expansion by new entrants. Entry by a single firm that will replicate at least the scale and strength of one of the merging firms is sufficient. Entry by one or more firms operating at a smaller scale may be sufficient if such firms are not at a significant competitive disadvantage.

10. Efficiencies

Competition usually spurs firms to achieve efficiencies internally. Nevertheless, a primary benefit of mergers to the economy is their potential to generate significant efficiencies and thus enhance the merged firm’s ability and incentive to compete, which may result in lower prices, improved quality, enhanced service, or new products. For example, merger-generated efficiencies may enhance competition by permitting two ineffective competitors to form a more effective competitor, e.g., by combining complementary assets. In a unilateral effects context, incremental cost reductions may reduce or reverse any increases in the merged firm’s incentive to elevate price. Efficiencies also may lead to new or improved products, even if they do not immediately and directly affect price. In a
coordinated effects context, incremental cost reductions may make coordination less likely or effective by enhancing the incentive of a maverick to lower price or by creating a new maverick firm. Even when efficiencies generated through a merger enhance a firm’s ability to compete, however, a merger may have other effects that may lessen competition and make the merger anticompetitive.

The Agencies credit only those efficiencies likely to be accomplished with the proposed merger and unlikely to be accomplished in the absence of either the proposed merger or another means having comparable anticompetitive effects. These are termed merger-specific efficiencies. Only alternatives that are practical in the business situation faced by the merging firms are considered in making this determination. The Agencies do not insist upon a less restrictive alternative that is merely theoretical.

Efficiencies are difficult to verify and quantify, in part because much of the information relating to efficiencies is uniquely in the possession of the merging firms. Moreover, efficiencies projected reasonably and in good faith by the merging firms may not be realized. Therefore, it is incumbent upon the merging firms to substantiate efficiency claims so that the Agencies can verify by reasonable means the likelihood and magnitude of each asserted efficiency, how and when each would be achieved (and any costs of doing so), how each would enhance the merged firm’s ability and incentive to compete, and why each would be merger-specific.

Efficiency claims will not be considered if they are vague, speculative, or otherwise cannot be verified by reasonable means. Projections of efficiencies may be viewed with skepticism, particularly when generated outside of the usual business planning process. By contrast, efficiency claims substantiated by analogous past experience are those most likely to be credited.

Cognizable efficiencies are merger-specific efficiencies that have been verified and do not arise from anticompetitive reductions in output or service. Cognizable efficiencies are assessed net of costs produced by the merger or incurred in achieving those efficiencies.

The Agencies will not challenge a merger if cognizable efficiencies are of a character and magnitude such that the merger is not likely to be anticompetitive in any relevant market. To make the requisite determination, the Agencies consider whether cognizable efficiencies likely would be sufficient to reverse the merger’s potential to harm customers in the relevant market, e.g., by preventing price

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13 The Agencies will not deem efficiencies to be merger-specific if they could be attained by practical alternatives that mitigate competitive concerns, such as divestiture or licensing. If a merger affects not whether but only when an efficiency would be achieved, only the timing advantage is a merger-specific efficiency.

14 The Agencies normally assess competition in each relevant market affected by a merger independently and normally will challenge the merger if it is likely to be anticompetitive in any relevant market. In some cases, however, the Agencies in their prosecutorial discretion will consider efficiencies not strictly in the relevant market, but so inextricably linked with it that a partial divestiture or other remedy could not feasibly eliminate the anticompetitive effect in the relevant market without sacrificing the efficiencies in the other market(s). Inextricably linked efficiencies are most likely to make a difference when they are great and the likely anticompetitive effect in the relevant market(s) is small so the merger is likely to benefit customers overall.
increases in that market. In conducting this analysis, the Agencies will not simply compare the magnitude of the cognizable efficiencies with the magnitude of the likely harm to competition absent the efficiencies. The greater the potential adverse competitive effect of a merger, the greater must be the cognizable efficiencies, and the more they must be passed through to customers, for the Agencies to conclude that the merger will not have an anticompetitive effect in the relevant market. When the potential adverse competitive effect of a merger is likely to be particularly substantial, extraordinarily great cognizable efficiencies would be necessary to prevent the merger from being anticompetitive. In adhering to this approach, the Agencies are mindful that the antitrust laws give competition, not internal operational efficiency, primacy in protecting customers.

In the Agencies’ experience, efficiencies are most likely to make a difference in merger analysis when the likely adverse competitive effects, absent the efficiencies, are not great. Efficiencies almost never justify a merger to monopoly or near-monopoly. Just as adverse competitive effects can arise along multiple dimensions of conduct, such as pricing and new product development, so too can efficiencies operate along multiple dimensions. Similarly, purported efficiency claims based on lower prices can be undermined if they rest on reductions in product quality or variety that customers value.

The Agencies have found that certain types of efficiencies are more likely to be cognizable and substantial than others. For example, efficiencies resulting from shifting production among facilities formerly owned separately, which enable the merging firms to reduce the incremental cost of production, are more likely to be susceptible to verification and are less likely to result from anticompetitive reductions in output. Other efficiencies, such as those relating to research and development, are potentially substantial but are generally less susceptible to verification and may be the result of anticompetitive output reductions. Yet others, such as those relating to procurement, management, or capital cost, are less likely to be merger-specific or substantial, or may not be cognizable for other reasons.

When evaluating the effects of a merger on innovation, the Agencies consider the ability of the merged firm to conduct research or development more effectively. Such efficiencies may spur innovation but not affect short-term pricing. The Agencies also consider the ability of the merged firm to appropriate a greater fraction of the benefits resulting from its innovations. Licensing and intellectual property conditions may be important to this enquiry, as they affect the ability of a firm to appropriate the benefits of its innovation. Research and development cost savings may be substantial and yet not be cognizable efficiencies because they are difficult to verify or result from anticompetitive reductions in innovative activities.

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15 The Agencies normally give the most weight to the results of this analysis over the short term. The Agencies also may consider the effects of cognizable efficiencies with no short-term, direct effect on prices in the relevant market. Delayed benefits from efficiencies (due to delay in the achievement of, or the realization of customer benefits from, the efficiencies) will be given less weight because they are less proximate and more difficult to predict. Efficiencies relating to costs that are fixed in the short term are unlikely to benefit customers in the short term, but can benefit customers in the longer run, e.g., if they make new product introduction less expensive.
11. Failure and Exiting Assets

Notwithstanding the analysis above, a merger is not likely to enhance market power if imminent failure, as defined below, of one of the merging firms would cause the assets of that firm to exit the relevant market. This is an extreme instance of the more general circumstance in which the competitive significance of one of the merging firms is declining: the projected market share and significance of the exiting firm is zero. If the relevant assets would otherwise exit the market, customers are not worse off after the merger than they would have been had the merger been enjoined.

The Agencies do not normally credit claims that the assets of the failing firm would exit the relevant market unless all of the following circumstances are met: (1) the allegedly failing firm would be unable to meet its financial obligations in the near future; (2) it would not be able to reorganize successfully under Chapter 11 of the Bankruptcy Act; and (3) it has made unsuccessful good-faith efforts to elicit reasonable alternative offers that would keep its tangible and intangible assets in the relevant market and pose a less severe danger to competition than does the proposed merger.16

Similarly, a merger is unlikely to cause competitive harm if the risks to competition arise from the acquisition of a failing division. The Agencies do not normally credit claims that the assets of a division would exit the relevant market unless both of the following conditions are met: (1) applying cost allocation rules that reflect true economic costs, the division has a persistently negative cash flow on an operating basis, and such negative cash flow is not economically justified for the firm by benefits such as added sales in complementary markets or enhanced customer goodwill;17 and (2) the owner of the failing division has made unsuccessful good-faith efforts to elicit reasonable alternative offers that would keep its tangible and intangible assets in the relevant market and pose a less severe danger to competition than does the proposed acquisition.

12. Mergers of Competing Buyers

Mergers of competing buyers can enhance market power on the buying side of the market, just as mergers of competing sellers can enhance market power on the selling side of the market. Buyer market power is sometimes called “monopsony power.”

To evaluate whether a merger is likely to enhance market power on the buying side of the market, the Agencies employ essentially the framework described above for evaluating whether a merger is likely to enhance market power on the selling side of the market. In defining relevant markets, the Agencies

16 Any offer to purchase the assets of the failing firm for a price above the liquidation value of those assets will be regarded as a reasonable alternative offer. Liquidation value is the highest value the assets could command for use outside the relevant market.

17 Because the parent firm can allocate costs, revenues, and intra-company transactions among itself and its subsidiaries and divisions, the Agencies require evidence on these two points that is not solely based on management plans that could have been prepared for the purpose of demonstrating negative cash flow or the prospect of exit from the relevant market.
focus on the alternatives available to sellers in the face of a decrease in the price paid by a hypothetical monopsonist.

Market power on the buying side of the market is not a significant concern if suppliers have numerous attractive outlets for their goods or services. However, when that is not the case, the Agencies may conclude that the merger of competing buyers is likely to lessen competition in a manner harmful to sellers.

The Agencies distinguish between effects on sellers arising from a lessening of competition and effects arising in other ways. A merger that does not enhance market power on the buying side of the market can nevertheless lead to a reduction in prices paid by the merged firm, for example, by reducing transactions costs or allowing the merged firm to take advantage of volume-based discounts. Reduction in prices paid by the merging firms not arising from the enhancement of market power can be significant in the evaluation of efficiencies from a merger, as discussed in Section 10.

The Agencies do not view a short-run reduction in the quantity purchased as the only, or best, indicator of whether a merger enhances buyer market power. Nor do the Agencies evaluate the competitive effects of mergers between competing buyers strictly, or even primarily, on the basis of effects in the downstream markets in which the merging firms sell.

Example 24: Merging Firms A and B are the only two buyers in the relevant geographic market for an agricultural product. Their merger will enhance buyer power and depress the price paid to farmers for this product, causing a transfer of wealth from farmers to the merged firm and inefficiently reducing supply. These effects can arise even if the merger will not lead to any increase in the price charged by the merged firm for its output.

13. Partial Acquisitions

In most horizontal mergers, two competitors come under common ownership and control, completely and permanently eliminating competition between them. This elimination of competition is a basic element of merger analysis. However, the statutory provisions referenced in Section 1 also apply to one firm’s partial acquisition of a competitor. The Agencies therefore also review acquisitions of minority positions involving competing firms, even if such minority positions do not necessarily or completely eliminate competition between the parties to the transaction.

When the Agencies determine that a partial acquisition results in effective control of the target firm, or involves substantially all of the relevant assets of the target firm, they analyze the transaction much as they do a merger. Partial acquisitions that do not result in effective control may nevertheless present significant competitive concerns and may require a somewhat distinct analysis from that applied to full mergers or to acquisitions involving effective control. The details of the post-acquisition relationship between the parties, and how those details are likely to affect competition, can be important. While the Agencies will consider any way in which a partial acquisition may affect competition, they generally focus on three principal effects.

First, a partial acquisition can lessen competition by giving the acquiring firm the ability to influence the competitive conduct of the target firm. A voting interest in the target firm or specific governance rights, such as the right to appoint members to the board of directors, can permit such influence. Such
influence can lessen competition because the acquiring firm can use its influence to induce the target firm to compete less aggressively or to coordinate its conduct with that of the acquiring firm.

Second, a partial acquisition can lessen competition by reducing the incentive of the acquiring firm to compete. Acquiring a minority position in a rival might significantly blunt the incentive of the acquiring firm to compete aggressively because it shares in the losses thereby inflicted on that rival. This reduction in the incentive of the acquiring firm to compete arises even if cannot influence the conduct of the target firm. As compared with the unilateral competitive effect of a full merger, this effect is likely attenuated by the fact that the ownership is only partial.

Third, a partial acquisition can lessen competition by giving the acquiring firm access to non-public, competitively sensitive information from the target firm. Even absent any ability to influence the conduct of the target firm, access to competitively sensitive information can lead to adverse unilateral or coordinated effects. For example, it can enhance the ability of the two firms to coordinate their behavior, and make other accommodating responses faster and more targeted. The risk of coordinated effects is greater if the transaction also facilitates the flow of competitively sensitive information from the acquiring firm to the target firm.

Partial acquisitions, like mergers, vary greatly in their potential for anticompetitive effects. Accordingly, the specific facts of each case must be examined to assess the likelihood of harm to competition. While partial acquisitions usually do not enable many of the types of efficiencies associated with mergers, the Agencies consider whether a partial acquisition is likely to create cognizable efficiencies.
In 2009, the Department of Justice and the Federal Trade Commission announced a process for reviewing the Horizontal Merger Guidelines and assessing whether they should be revised to better reflect actual practice. The process included significant reflection within the Department, public workshops, and opportunities for public comment, including an opportunity to comment on a draft revision.\footnote{U.S. Dep’t of Justice & Fed. Trade Comm’n, Horizontal Merger Guidelines Review Project (2009–10) [hereinafter Workshop Materials] (materials include transcripts, public comments, and draft Guidelines), available at http://www.ftc.gov/bc/workshops/hmg/index.shtml.}


The foundation for the 2010 Guidelines was laid in prior Guidelines. The core of the 1992 Guidelines remains: using the hypothetical monopolist test to analyze markets, assessing a merger’s potential to harm consumers through coordinated or unilateral effects, and considering the prospect of entry or efficiencies to avert harm.\footnote{U.S. Dep’t of Justice & Fed. Trade Comm’n, Horizontal Merger Guidelines (1992) [hereinafter 1992 Guidelines], available at http://www.justice.gov/atr/hmerger/11250.htm.} The imprint of other Guidelines is found as well. For instance, the 1982 Guidelines introduced the hypothetical monopolist test,\footnote{U.S. Dep’t of Justice, Merger Guidelines § II.A (1982) [hereinafter 1982 Guidelines], available at http://www.justice.gov/atr/hmerger/11248.htm.} and the 1997 revisions to the Guidelines discussion of efficiencies are carried...
forward.\(^5\) In addition, the 2010 Guidelines incorporate much of the 2006 Commentary on the Horizontal Merger Guidelines.\(^6\)

The decision to build upon the existing framework is in keeping with the views of the Antitrust Modernization Commission, which concluded that U.S. merger policy “is fundamentally sound” and “has benefited significantly” from the Guidelines.\(^7\) Courts, too, accept the basic Guidelines structure. For instance, the Fifth Circuit Court of Appeals recently described the Guidelines as “persuasive authority when deciding if a particular acquisition violates antitrust laws.”\(^8\) Similarly, there was consensus among workshop participants and those who submitted public comments that the basic Guidelines framework does not require significant overhaul.\(^9\)

In contrast to the consensus among the mainstream of antitrust, the authors of “Tally-Ho!”: UPP and the 2010 Horizontal Merger Guidelines maintain that the Guidelines are, and have been, fundamentally mistaken in two areas: defining markets and assessing unilateral effects.\(^10\) Their views, which are in large measure retracings of worn-out attacks on the 1992 Guidelines,\(^11\) run contrary to years of enforcement practice, rest on distortions of congressional intent and judicial precedent, and proceed from a rejection of the economic approach that has guided antitrust for decades.

This comment addresses the decision to build upon the existing Guidelines approach to market definition and unilateral effects. It briefly touches upon a few other important aspects of the 2010 Guidelines.

I. MARKET DEFINITION

The Supreme Court has articulated several principles regarding market definition. For instance, the Court has stated that a “market is composed of products that have reasonable interchangeability for the purposes for which they are produced—price, use and qualities considered.”\(^12\) The Court also has explained that market definition must avoid “the indefensible extremes” of un-


\(^8\) Chi. Bridge & Iron Co. v. FTC, 534 F.3d 410, 431 n.11 (5th Cir. 2008).

\(^9\) See Workshop Materials, supra note 1.


duly expansive markets that “make the effect of the merger upon competition seem insignificant” and unduly narrow markets that place competing parties “in different markets.”13 Thus, attempting to seek out every substitute for a product misses the point; as the Court puts it: “For every product, substitutes exist. But a relevant market cannot meaningfully encompass that infinite range. The circle must be drawn narrowly to exclude any other product to which, within reasonable variations in price, only a limited number of buyers will turn . . . .”14 Significantly, the Court has rejected the claim that the antitrust laws require “delineat[ing] with perfect accuracy” a market, recognizing that “fuzziness” is “inherent in any attempt.”15 That flexibility flows from the purpose of defining markets—helping to assess a merger’s potential to harm consumers.

The 1982 Guidelines established that the Department would define markets under these precedents using the hypothetical monopolist test. In general, the test defines markets around the possibility of price increases were a single firm to have pricing control over a group of products.16

Innovative at the time of its adoption in 1982, the test is now well-established. The horizontal merger complaints filed by the Department since the 1982 Guidelines have defined markets under the test. Courts have embraced the analytical rigor it gives the relatively general pronouncements of the Supreme Court.17 Moreover, it has been adopted in many jurisdictions outside the United States.18

14 Times-Picayune Publ’g Co. v. United States, 345 U.S. 594, 612 n.12 (1953).
15 Phila. Nat’l Bank, 374 U.S at 360 & n.37; see also du Pont, 351 U.S. at 395 (“[N]o more definite rule can be declared . . . .”). The Staples court similarly made clear that the antitrust laws do not require identifying the full set of relevant markets to which every product in the economy could be uniquely assigned:

The Court acknowledges that there is, in fact, a broad market encompassing the sale of consumable office supplies by all sellers of such supplies, and that those sellers must, at some level, compete with one another. However, the mere fact that a firm may be termed a competitor in the overall marketplace does not necessarily require that it be included in the relevant product market for antitrust purposes.

In contrast, the *Tally-Ho* authors criticize the hypothetical monopolist test and its “inherent flaws,” describing two decisions as apparent support for their criticism. Both courts, however, accepted the appropriateness of the test and only questioned its application to the particular facts at issue. The *Tally-Ho* authors also assert a conflict between Court precedent and the Guidelines acknowledgment that “groups of products may satisfy the hypothetical monopolist test without including the full range of substitutes from which customers choose.” That observation, which was also made in the 2006 Commentary, is entirely in keeping with the Court’s admonition that the “circle must be drawn narrowly” to exclude products to which few customers would turn in the event of a price increase.

The *Tally-Ho* authors also maintain that the test conflicts with congressional intent. In 1950, Congress amended the Clayton Act and removed the reference to effects on commerce in a “community,” in part because of “fear of literal prohibition of all but *de minimis* mergers through the use of the word ‘community.’” The amendments thus made clear that the Clayton Act concerns “the geographic area of effective competition in [a] relevant line of commerce.” No reasonable assessment of merger enforcement over the nearly thirty years since the hypothetical monopolist test’s introduction could conclude that the test has led to the targeting of *de minimis* mergers that affect less than a “line of commerce.”

\[19\] *Tally-Ho*, supra note 10, at 616.
\[20\] Id. at 615.

\[22\] 2010 Guidelines, supra note 2, § 4.1.1.
\[23\] 2006 Commentary, supra note 6, at 6 (“Defining markets under the Guidelines’ method does not necessarily result in markets that include the full range of functional substitutes from which customers choose.”).

\[27\] *Id.*
The 2010 Guidelines contain a number of important clarifications and refinements concerning market definition. One is substantial expansion of the discussion of market definition. That increase reflects the continued importance of market definition to the merger review process.

Another addition is the express acknowledgement that merger analysis “need not start with market definition.” 28 Confusion over the sequencing of merger review has existed since the 1982 Guidelines, which some perceived to describe a rigidity that never existed. Two years later, the Department amended the Guidelines to provide that the Department “will apply the standards of the Guidelines reasonably and flexibly to the particular facts and circumstances of each proposed merger.” 29 That explanation carried over to the 1992 Guidelines, and the 2006 Commentary similarly acknowledged that “the Agencies do not settle on a relevant market definition before proceeding to address other issues.” 30

That flexibility is necessary to enable the efficient use of government resources. For instance, document review may reveal evidence of actual or likely market effects, and trigger significant concern, even before the contours of a relevant market are clear. 31 That evidence also would be germane to defining the relevant market. Likewise, when investigating the possibility of unilateral effects, there may be no need to settle on a market definition when evidence indicates that the diversion ratios are very low and consumers do not view the merging parties’ products as particularly close substitutes; conversely, market definition may be more of a gating issue for a coordinated effects investigation. 32

28 2010 Guidelines, supra note 2, § 4.0.
30 2006 Commentary, supra note 6, at 5.
31 On the relevance of direct evidence of competitive effects, see generally FTC v. Ind. Fed’n of Dentists, 476 U.S. 447, 461 (1986) (relying on evidence of “actual, sustained adverse effects on competition”); NCAA v. Bd. of Regents of Univ. of Okla., 468 U.S. 85, 110 (1984) (“This naked restraint on price and output requires some competitive justification even in the absence of a detailed market analysis.”). In a challenge to a completed merger, relevant effects evidence could include evidence of actual price increases. In a challenge to a proposed merger, relevant evidence could include credible statements by top executives that the proposed merger will reduce competition, see, for example, FTC v. Whole Foods Market, 548 F.3d 1028, 1032 (D.C. Cir. 2008), or natural experiments comparing pre-merger prices in geographic markets where the merging firms do not compete to those where they do, see, for example, FTC v. Staples, Inc., 970 F. Supp. 1066, 1076 (D.D.C. 1997) (finding evidence that prices were higher in geographic markets where the merging parties did not compete to be “compelling”). See generally 2006 Commentary, supra note 6, at 10–11.
32 The Agencies made both points in 2006. See 2006 Commentary, supra note 6, at 16 ("[M]arket concentration may be unimportant under a unilateral effects theory of competitive harm."); id. at 20 (emphasizing the relevance of the number of competitors in a market when assessing coordinated effects).
The *Tally-Ho* authors incorrectly assert that the flexibility described in the 2010 Guidelines has “significantly” and “fundamentally” changed the merger review process.\(^3\) To the contrary, what has changed is an increase in transparency about a longstanding reality. At the same time, it is worth repeating that the Department will continue defining relevant markets in its merger complaints in accord with Supreme Court precedent.\(^3\)

The 2010 Guidelines make a few other important clarifications to the discussion of market definition. The hypothetical monopolist test frequently can reveal more than one market affected by a merger. Since 1984, the Guidelines have provided that the smallest group of products that satisfies the test will “generally” be a relevant market, without further discussion.\(^3\) The 2010 Guidelines now explain that, when relying primarily on market shares and concentration (as may be the case, for instance, under a theory of harm focused on coordinated effects), the smallest market satisfying the test is “usually” a relevant market.\(^3\) That is not always the case, however, because the antitrust laws are designed to prevent anticompetitive effects in any relevant market. The 2010 Guidelines also describe how defining markets sometimes entails analyzing, as one of a number of factors considered in implementing the hypothetical monopolist test, “the percentage of sales lost by one product in the candidate market, when its price alone rises, that is recaptured by other products in the candidate market.”\(^3\) As the Supreme Court has explained, market definition appropriately considers the “cross-elasticity of demand between products” as illustrated by “the responsiveness of the sales of one product to price changes of the other.”\(^\) 38

II. UNILATERAL EFFECTS

The 1992 Guidelines were the first to use the phrase “unilateral effects.” The antecedent concern is found in the 1982 and 1984 Guidelines, which provided that the Department was “likely to challenge” essentially any merger involving a “leading firm,” which was defined as any firm with a market share

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33 *Tally-Ho*, supra note 10, at 592.
34 Carl Shapiro, Deputy Ass’t Att’y Gen., Update from the Antitrust Division, Remarks as Prepared for the ABA Section of Antitrust Law Fall Forum 15 (Nov. 18, 2010) (“The Division recognizes the necessity of defining a relevant market as part of any merger challenge we bring.”), available at http://www.justice.gov/atr/public/speeches/264295.pdf.
36 2010 Guidelines, supra note 2, § 4.1.1. To help assure that close substitutes are not omitted from a market and avoid unduly narrow markets, the 2010 Guidelines also provide that “[w]hen applying the hypothetical monopolist test to define a market around a product offered by one of the merging firms, if the market includes a second product, the Agencies will normally also include a third product if that third product is a closer substitute for the first product than is the second product.” Id.
37 Id. § 4.1.3.
greater than 35 percent.\textsuperscript{39} As former Assistant Attorney General William Baxter explained, “It was the judgment of the Division that at about 35%, the danger of market power becomes sufficiently great to overwhelm any concern for the potential efficiencies that might be lost from prohibiting a leading firm merger.”\textsuperscript{40}

The 1992 Guidelines addressed the possibility of a merger’s potential to enhance or maintain a firm’s market power in a more nuanced way, introducing the concept of diversion and the possibility that, “depending on relative margins,” a firm might find it profitable to raise price after a merger because some customers would “be diverted to the product of the merger partner.”\textsuperscript{41} The 1992 Guidelines also state that adverse unilateral effects are possible when “a significant share of sales in the market [is] accounted for by consumers who regard the products of the merging firms as their first and second choices.”\textsuperscript{42} Not much more detail was included, although the 1992 Guidelines did provide that, in certain circumstances, “significant” diversion would be “presumed” when “the merging firms have a combined market share of at least thirty-five percent.”\textsuperscript{43}

The Agencies have accumulated substantial experience in assessing unilateral effects since 1992; indeed, a majority of the Department’s merger enforcement actions since 1992 have involved unilateral effects theories of harm. Reflecting the significant learning achieved during those intervening eighteen years, the 2010 Guidelines contain a greatly expanded discussion of unilateral effects broken into four sections dealing with (1) pricing, (2) bargaining and auctions, (3) capacity and output for homogeneous products, and (4) innovation and product variety.

The \textit{Tally-Ho} authors claim that, by focusing on the loss of competition between merging firms, unilateral effects theories of harm are “inconsistent” with Section 7.\textsuperscript{44} The claim that continued concern with unilateral effects is at odds with the Clayton Act—wherein Congress provided “authority for arresting mergers at a time when the trend to a lessening of competition in a line of commerce was still in its incipiency”\textsuperscript{45}—departs from any sensible reading of the statute or its legislative history. Although unilateral effects arise from the internalization of the competition between the merging firms, mergers ca-
pable of creating adverse unilateral effects are obviously able to produce a
general effect on competition of the sort Section 7 was intended to forestall.
Indeed, in some circumstances, the products of the merging firms may them-
selves comprise a relevant market. A vast weight of economic learning contra-
dicts the Tally-Ho authors’ equally sweeping—and incorrect—argument that
mergers cannot lead to adverse unilateral effects unless the merging firms
“uniquely occupy a product space” that no other firm participates in.46

The 2010 Guidelines substantially expand the discussion of unilateral ef-
fects and make several important clarifications. One is the omission of the
1992 Guidelines presumption that, in some limited circumstances, diversion
among the products of firms whose combined market share exceeds 35 per-
cent is “significant.” Although criticized by the Tally-Ho authors,47 the omis-
sion of the presumption indicates no change in direction, but merely reflects
actual practice, in which it is often found to be inapt. Importantly, that does
not mean that unilateral effects are impossible when the merging firms’ com-
bined share is less than 35 percent. Rather, it reflects that facts drive the anal-
ysis of unilateral effects, undermining the ability to make categorical
assertions.

The inability to make categorical assertions relates to the issue of the level
of generality appropriate for the Guidelines. For some, the 2010 Guidelines
will contain too much detail; for others, too little. The 2010 Guidelines seek to
provide concrete direction yet also appropriately take into account the in-
tensely fact-driven nature of merger analysis, which often precludes describ-
ing actual practice in absolute terms without excessive caveats that would
undermine the overall clarity of the Guidelines. As prior versions have, the
2010 Guidelines note that they “may be revised from time to time as neces-
sary to reflect significant changes in enforcement policy, to clarify existing
policy, or to reflect new learning.”48 Future iterations can be counted on to
provide more detail on important, recurring points as appropriate, just as the
2010 Guidelines clarify important points in the 1992 Guidelines.

One sentence in the 2010 Guidelines that has attracted attention provides
that “[i]n some cases, where sufficient information is available, the Agencies
assess the value of diverted sales, which can serve as an indicator of the up-

46 Tally-Ho, supra note 10, at 631. As former Deputy Assistant Attorney General Carl Shapiro
has detailed, the economic principles of unilateral effects analysis have been widely used and
developed over the past twenty years. See generally Carl Shapiro, The 2010 Horizontal Merger
47 Tally-Ho, supra note 10, at 625. In their obscure criticism, the Tally-Ho authors appear to
equate the omission of the presumption respecting diversion in the 2010 Guidelines to the elimi-
nation of a “safe harbor.” Id. That argument turns the text of the 1992 Guidelines and the Guide-
lines history sketched above on their heads.
48 2010 Guidelines, supra note 2, § 1 n.1.
ward pricing pressure on the first product resulting from the merger." Because market shares can be an imperfect proxy for market power and substitution patterns, the value of diverted sales can be, and has been, useful in assessing the closeness of substitution.

Those criticizing the discussion of the value of diverted sales in the 2010 Guidelines miss the mark. Recognizing a tool that economists (both those within the Agencies and those hired by merging firms to advocate on their behalf) use during merger review increases transparency. The Tally-Ho authors incorrectly assert that considering the value of diverted sales is inappropriate because it always suggests competitive harm, but that criticism ignores the explicit recognition in the 2010 Guidelines that “if the value of diverted sales is proportionally small, significant unilateral price effects are unlikely.” Indeed, a similarly unfounded criticism applies to the use of market shares, HHIs, or any measure of concentration—tools that are all well-accepted by the antitrust mainstream.

III. CONCLUSION

The 2010 Guidelines reflect actual practice and incorporate the accumulated experience of the eighteen years since the last significant Guidelines update. Although this comment has highlighted the continuity among Guidelines past and present, there are a number of important additions that make significant contributions to increasing the transparency of merger policy. The new section addressing evidence of adverse competitive effects describes the actual evidence-gathering work that comprises a significant part of merger review. Similarly, the increased HHI thresholds more accurately describe actual practice. The new sections on targeted customers and price discrimination, powerful buyers, mergers of competing buyers, and partial acquisitions also should provide guidance on issues that repeatedly come up but received

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49 Id. § 6.1. The 2010 Guidelines use the phrase “upward pricing pressure” once, reflecting that it is one of many factors that a merger review may entail. In contrast, the Tally-Ho authors mention “upward pricing pressure” or “UPP” over 250 times. The Tally-Ho authors also incorrectly assert that the Southern District of New York has “expressly rejected the UPP analysis.” Tally-Ho, supra note 10, at 609 n.99. To the contrary, the court merely denied a plaintiff’s motion to amend its complaint three and a half years after filing suit, citing the plaintiff’s “undue delay” and “clear prejudice to the opposing party.” City of New York v. Group Health Inc., No. 06 Civ. 13122 (RJS), 2010 WL 2132246, at *6 (S.D.N.Y. May 11, 2010).

50 Tally-Ho, supra note 10, at 625.

51 2010 Guidelines, supra note 2, § 6.1.

52 The 2010 Guidelines do not adopt the value of diverted sales as the exclusive factor for any investigation. Just as market shares and HHIs are appropriately used as part of the merger review process despite their limits, so too is the value of diverted sales. It is worth noting that the 2010 Guidelines do not attach presumptions to high levels of diverted sales values, in contrast to the explicit anticompetitive presumption that has long applied to mergers resulting in significant HHI increases. See, e.g., id. § 5.3; 1992 Guidelines, supra note 3, § 1.51(c); 1982 Guidelines, supra note 4, § III.A.1.c.
only brief mention in earlier Guidelines. Finally, the revisions to the coordinated-effects discussion also usefully clarify the Department’s continued commitment to blocking mergers posing the threat of express or tacit collusion.53

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53 *See generally* 4 *Phillip E. Areeda & Herbert Hovenkamp, Antitrust Law* ¶ 901b2 (3d ed. 2009).

The more frequent danger associated with mergers, however, is not the express cartel but tacit coordination. If the significant actors in a market are few enough, they may recognize their interdependence and succeed in coordinating their prices tacitly in the manner described elsewhere. Such “oligopoly” pricing is feared by antitrust policy even more than express collusion, for tacit coordination, even when observed, cannot easily be controlled directly by the antitrust laws. A central objective of merger policy is to obstruct the creation or reinforcement by merger of such oligopolistic market structures in which tacit coordination can occur.

*Id.*
THE 2010 HORIZONTAL MERGER GUIDELINES:  
FROM HEDGEHOG TO FOX IN FORTY YEARS  

CARL SHAPIRO*  

The U.S. Department of Justice and the Federal Trade Commission recently updated their Horizontal Merger Guidelines,¹ which build upon and replace the 1992 Guidelines.² The revised Guidelines are the product of an extensive team effort at the Agencies that took place over roughly a year, under the leadership of Assistant Attorney General Christine Varney and FTC Chairman Jon Leibowitz. The process for revising the Guidelines was lengthy, collaborative, and open: the Agencies posted a series of questions, inviting public comment on possible revisions; numerous useful public comments were received and reviewed; the Agencies sponsored five public workshops at which panelists discussed possible revisions to the Guidelines; subsequently, the FTC made public a draft of the proposed Guidelines, again inviting additional public comments; numerous thoughtful comments were again received and reviewed; and in response to those comments, the proposed Guidelines

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were further clarified. Inevitably, however, many of the questions raised in the public comments submitted in response to the proposed Guidelines are not explicitly addressed in the final Guidelines. In this article, I respond to some of those questions, especially the questions pertaining to the economic principles underlying the revised Guidelines. I also elaborate in greater detail on some of the points made in the Guidelines themselves.

I. HISTORICAL PERSPECTIVE: THE HEDGEHOG AND THE FOX

The 2010 Guidelines are best understood in historical context. They reflect the ongoing evolution of merger enforcement that has taken place since the DOJ first issued merger guidelines in 1968. The 2010 Guidelines rely heavily on earlier versions of the Guidelines, especially those released in 1982 and 1992, and on the 2006 Commentary on the Merger Guidelines. Many of the approaches in the 2010 Guidelines that some commentators have considered novel actually are contained in those earlier statements of merger enforcement policy.

Isaiah Berlin’s famous allusion to the different ways in which the Hedgehog and the Fox view the world is a useful model for how to think about the evolution of the Merger Guidelines. The hedgehog knows one big thing. Likewise, the 1968 Guidelines were based on one big idea: horizontal mergers that increase market concentration inherently...
are likely to lessen competition. By today’s standards, the 1968 Guidelines are rather shocking. For example, in a market in which the combined share of the four largest firms is at least 75 percent, they state that the Department “will ordinarily challenge” a merger if the acquiring firm’s share is at least 15 percent and the acquired firm’s share is at least 1 percent. Few would advocate such an enforcement stance today.

However, this focus on market concentration reflected unambiguous Supreme Court precedent. In Brown Shoe, the Court stated: “The dominant theme pervading congressional consideration of the 1950 amendments [to § 7 of the Clayton Act] was a fear of what was considered to be a rising tide of economic concentration in the American economy.” In Philadelphia National Bank, the court quoted this passage from Brown Shoe and then stated:

This intense congressional concern with the trend toward concentration warrants dispensing, in certain cases, with elaborate proof of market structure, market behavior, or probable anticompetitive effects. Specifically, we think that a merger which produces a firm controlling an undue percentage share of the relevant market, and results in a significant increase in the concentration of firms in that market is so inherently likely to lessen competition substantially that it must be enjoined in the absence of evidence clearly showing that the merger is not likely to have such anticompetitive effects.

One cannot help but marvel at how far merger enforcement has moved over the past forty years, with no change in the substantive provisions of the Clayton Act and very little new guidance on horizontal mergers from the Supreme Court. But the Court has given a great deal of guidance in Sherman Act cases, moving away from simple rules and towards an approach emphasizing the practical reality of the market and the likely effects of the practice in question. As Justice Souter explained in California Dental, “What is required . . . is an enquiry meet for the case, looking to the circumstances, details, and logic of a restraint.”

Returning to Berlin’s prototypes, the fox knows many things. Likewise, merger enforcement in recent years has become increasingly eclect-

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7 Id. See, e.g., Stanley Works v. FTC, 469 F.2d 498, 508 (2d Cir. 1972) (finding that the acquisition of a company with 1 percent of the market by a company with 22 percent of the market violated Section 7).
tic, reflecting the enormous diversity of industries in which the Agencies review mergers and the improved economic toolkit available. The Agencies and the courts look at a wide variety of evidence and use a wide variety of methods to determine whether mergers may substantially lessen competition. Based on decades of experience examining mergers, the Agencies recognize that each industry has unique features and each merger presents unique circumstances.

The transition of merger enforcement from hedgehog to fox can be traced through the various merger guidelines published from 1968 to 2010. At times, most notably in 1982, new guidelines have spurred changes in Agency enforcement practice. At other times, including 2010, new guidelines have primarily been an exercise in transparency, reflecting ongoing changes in Agency enforcement practice and advances in economic learning.

The 1982 Guidelines were a revolution. Five innovations formed the foundation on which all subsequent Merger Guidelines have been built:

1. The 1982 Guidelines articulated a “unifying theme” for merger enforcement: “that mergers should not be permitted to create or enhance ‘market power’ or to facilitate its exercise.”11 This was a dramatic departure from the 1968 Guidelines, which stated that “the primary role of Section 7 enforcement is to preserve and promote market structures conducive to competition.”12 The unifying theme from the 1982 Guidelines is repeated in the introductory section of the 2010 Guidelines.

2. The 1982 Guidelines introduced the hypothetical monopolist test (HMT) for defining the relevant market.13 The HMT has been widely accepted by the courts and other jurisdictions. Section 4 of the 2010 Guidelines, “Market Definition,” retains the HMT and explains its correct implementation in greater detail.

3. The 1982 Guidelines introduced the Herfindahl-Hirschman Index (HHI) into merger analysis and established enforcement thresholds based on the post-merger HHI and the change in the HHI resulting from the merger. Section 5 of the 2010 Guidelines, “Market Participants, Market Shares, and Market Concentration,” retains the usage of HHI thresholds, adjusting them upwards.

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12 1968 Guidelines, supra note 6, ¶ 2.
4. The 1982 Guidelines expanded the discussion of competitive effects, somewhat downplaying the role of market concentration in comparison with the 1968 Guidelines. The 2010 Guidelines continue this trend.

5. The 1982 Guidelines provided a list of factors that affect the ease and profitability of collusion. Many of these same factors can be found in Section 7 of the 2010 Guidelines, “Coordinated Effects.”

While the 1982 Guidelines were a dramatic step forward in merger enforcement policy, they proved to be limited in some respects due to their heavy emphasis on what today we refer to as “coordinated effects,” and specifically the danger that the merger would increase the likelihood of collusion, either express or tacit.

The 1982 Guidelines were written with relatively homogeneous, industrial products in mind. Product differentiation was considered as a factor affecting the ease and profitability of collusion, that “will be taken into account only in relatively extreme cases.” This mindset reflected longstanding antitrust concerns about the performance of concentrated markets for basic industrial commodities. Antitrust attention was focused on markets of this type during the industrial age—the age of steel. The Sherman Act itself was motivated by concerns about collusion in markets for homogeneous products, which took the form of the 19th century trusts. The HHI thresholds were thus best suited to evaluate concerns about collusion in markets for homogeneous products. Indeed, in his classic 1964 article, George Stigler derived expressions involving the HHI from a model of collusion.

The Guidelines were slightly revised in 1984, but the next major change arrived with the 1992 Guidelines, the first that were jointly issued by the DOJ and the FTC. The 1992 Guidelines increased the sophistication of the economic analysis and explained more fully how the Agencies evaluate various types of competitive effects. These changes reflected the accumulation of Agency experience and the advance of economic learning during the 1980s. Two innovations in the 1992 Guidelines stand out.

First, the most significant advance in the 1992 Guidelines was their introduction of “unilateral effects.” The earlier guidelines had focused

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14 1982 Guidelines, supra note 11, § III.C.1.a.

15 See George Stigler, A Theory of Oligopoly, 72 J. POL. ECON. 44 (1964). Stigler’s theory of oligopoly had considerable influence on William Baxter, under whose leadership as Assistant Attorney General for Antitrust the 1982 Guidelines were released.

almost exclusively on coordinated effects. They considered what we now call "unilateral effects" only via their "leading firm proviso," which comprised a single paragraph in the 1984 Guidelines. In recent years, more DOJ investigations have involved unilateral effects than coordinated effects. The 2010 Guidelines build upon the treatment of unilateral effects in the 1992 Guidelines.

Second, the 1992 Guidelines introduced a more detailed and sophisticated analysis of entry. Entry analysis in the 1992 Guidelines is built upon the principle that entry must be "timely, likely, and sufficient" to deter or counteract the competitive effects of concern. The 2010 Guidelines retain this basic approach to the analysis of entry.

The leading firm proviso in the 1984 Guidelines stated that "the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent." The aim of the proviso was to prevent "mergers that may create or enhance the market power of a single dominant firm." The 1992 Guidelines expanded on the leading firm proviso, developing the idea of unilateral effects, i.e., that eliminating competition between the merging firms could itself constitute a substantial lessening of competition, even without post-merger coordination between the merged firm and its remaining rivals. Critically, the 1992 Guidelines explained how such unilateral effects could be diagnosed in markets with differentiated products, where the adverse competitive effects of concern typically are not uniform throughout the relevant market. The introduction of unilateral effects in the 1992 Guidelines reflected and anticipated a shift in merger enforcement away from relatively homogeneous industrial commodities and towards more differentiated products. While the Guidelines necessarily apply to all industries, the 1992 Guidelines were a major step in the evolution of antitrust enforcement from the industrial age to the information age.

The next change to the Guidelines was the substantial revision and expansion in 1997 of the treatment of merger efficiencies. The 1997
changes reflect an appreciation that mergers can promote competition by enabling efficiencies, and that such efficiencies can be great enough to reduce or reverse adverse competitive effects that might arise in their absence. The 2010 Guidelines make very few changes to the treatment of efficiencies articulated in 1997.

II. THE TRIUMPH OF THE FOX

The 2010 Guidelines reflect the ongoing trend in merger enforcement from hedgehog to fox that has continued since 1992.

These Guidelines should be read with the awareness that merger analysis does not consist of uniform application of a single methodology. Rather, it is a fact-specific process through which the Agencies, guided by their extensive experience, apply a range of analytical tools to the reasonably available and reliable evidence to evaluate competitive concerns in a limited period of time.23

Many observers have noted specifically that the 2010 Guidelines place less weight on market shares and market concentration than did predecessors. This is a central example of the fox’s eclectic approach, tailoring the methods used to the case at hand and to the available evidence.

The 2010 Guidelines also follow a more integrated and less mechanistic approach. Section 0.2 from the 1992 Guidelines described a step-by-step approach followed by the Agencies: (1) market definition and concentration; (2) competitive effects; (3) entry; (4) efficiencies; and (5) failing firm defense. Even in 1992 the Agencies did not rigidly follow these steps, and by 2009 many witnesses observed at the hearings that they gave an inaccurate impression of Agency practice. The 2006 Commentary acknowledged as much, stating that “the Agencies do not apply the Guidelines as a linear, step-by-step progression that invariably starts with market definition and ends with efficiencies or failing assets.”24 There was a consensus at the hearings that new guidelines should reflect the movement away from the step-by-step approach described in the

Section 4 of these Guidelines, relating to Efficiencies, appears as it was issued in revised form by the Department of Justice and the Federal Trade Commission on April 8, 1997; and the footnotes in Section 5 of the Guidelines have been renumbered accordingly. The remaining portions of the Guidelines were unchanged in 1997, and appear as they were issued on April 2, 1992.

23 2010 Guidelines, supra note 1, § 1.
24 2006 Commentary, supra note 4, at 2. The 2006 Commentary then states: “Three significant principles are generally applicable throughout.” Id. These principles are (1) the Agencies’ focus is on competitive effects; (2) investigations are fact-driven, intensive processes; and (3) the same evidence often is relevant to multiple elements of the analysis. See id. at 2–4. These principles are endorsed and embraced in the revised Guidelines. See 2010 Guidelines, supra note 1, §§ 1–2 (discussing principles one and two).
The revised Guidelines emphasize that merger analysis ultimately is about competitive effects. The new Section 2, “Evidence of Adverse Competitive Effects,” provides guidance about the types of evidence the Agencies normally seek, and the sources of evidence the Agencies normally use, to inform their analysis of competitive effects. The section is placed near the front of the Guidelines because investigations usually start with the formulation of candidate theories of harm to competition and the exploration of evidence to support or reject those theories. In most cases, especially where market boundaries are unclear, DOJ staff will analyze evidence of possible harm before it has determined the scope of the relevant market. Indeed, the same piece of evidence may be relevant to competitive effects and to market definition, as emphasized in the 2006 Commentary. The 2010 Guidelines make a similar observation in Section 4: “Evidence of competitive effects can inform market definition, just as market definition can be informative regarding competitive effects.”

Thus, like the fox, the 2010 Guidelines embrace multiple methods. But this certainly does not mean they reject the use of market concentration to predict competitive effects, as can be seen in Sections 2.1.3 and 5. The 2010 Guidelines recognize that levels and changes in market concentration are more probative in some cases than others. In particular, as the revised Guidelines explain, the Agencies place considerable weight on HHI measures in cases involving coordinated effects. The statement that “merger analysis does not consist of uniform application of a single methodology” certainly also does not mean that the DOJ will dispense with identifying the relevant line of commerce and section of the country when going to court to challenge a merger. Instead, it means that predictions about competitive effects may rely on evidence

25 This consensus reflected not only Agency practice but the gradual decline of the structural presumption. In 1990, the influential Baker Hughes decision emphasized that the analysis was not confined to market concentration: “That the government can establish a prima facie case through evidence on only one factor, market concentration, does not negate the breadth of this analysis. Evidence of market concentration simply provides a convenient starting point for a broader inquiry into future competitiveness.” United States v. Baker Hughes, Inc., 908 F.2d 981, 984 (D.C. Cir. 1990).

20 See 2006 Commentary, supra note 4, at 3.

27 The DOJ places more weight on evidence of diversion ratios and margins in cases involving unilateral price effects. Market shares can be informative about diversion ratios. See 1992 Guidelines, supra note 2, § 2.21.

20 2010 Guidelines, supra note 1, § 4.
other than market shares and market concentration. For this reason, the revised Guidelines state in Section 4: “The measurement of market shares and market concentration is not an end in itself, but is useful to the extent it illuminates the merger’s likely competitive effects.”

Concern that the revised Guidelines, with their more flexible approach, provide less valuable guidance to the business community and increase the uncertainty faced by companies considering or undertaking horizontal mergers is unwarranted.

First, the revised Guidelines, by increasing transparency and providing more up-to-date guidance, should allow the business community to assess more accurately how the Agencies are likely to evaluate proposed horizontal mergers. The public hearings confirmed our internal assessment that actual practice had departed from the 1992 Guidelines. To a considerable degree, these departures were already reflected in the 2006 Commentary: “In some investigations, before having determined the relevant market boundaries, the Agencies may have evidence that more directly answers the ‘ultimate inquiry in merger analysis,’ i.e., ‘whether the merger is likely to create or enhance market power or facilitate its exercise.’”

To respond to this discrepancy between the 1992 Guidelines and actual practice, both Assistant Attorney General Varney and Chairman Leibowitz stated their goal was to provide transparency by updating the Guidelines themselves, while referencing the 2006 Commentary as a useful supplement to the 2010 Guidelines. For example, Assistant Attorney General Varney explained in a speech in January 2010 that a major goal of revising the Guidelines was to provide greater transparency:

A consistent theme running through the panels is that there are indeed gaps between the Guidelines and actual agency practice—gaps in

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Although market power and market definition have a role in antitrust analysis, their proper roles are as parts of and in reference to the primary evaluation of the alleged anticompetitive conduct and its likely market effects. They are not valued for their own sake, but rather for the roles they play in an evaluation of market effects.

Id. at 188.

30 2006 Commentary, supra note 4, at 10 (quoting 1992 Guidelines, supra note 2, § 0.2).
the sense of both omissions of important factors that help predict the competitive effects of mergers and statements that are either misleading or inaccurate. Those gaps are something that we are aware of within the Division, and they have been reflected in several documents issued by the Agencies over the years, including for instance the 2006 Commentary on the Horizontal Merger Guidelines and the 2003 Merger Challenges Data. Our panelists and commentators have affirmed that many outside the Agencies recognize and appreciate these gaps as well.

Gaps between what the Agencies say we do and what we actually do are unfortunate for a number of reasons. Our Guidelines are meant to inform practitioners and the business community of the Agencies’ standards for evaluating mergers. Gaps run counter to our goal of being transparent. That transparency helps businesses make accurate predictions about our likely enforcement intentions and adjust their behavior accordingly. Gaps increase uncertainty and thus can lead to unnecessary surprises. We want to avoid that.31

Second, the supposed simplicity and predictability based on market definition and market concentration was more apparent than real. Market definition is often disputed. In many merger investigations, such as the Staples or Whole Foods cases,32 the merging parties assert a broad market in which they argue that the post-merger HHI or the change in HHI is small, but the Agencies respond that the hypothetical monopolist test properly leads to a narrower market. Unfortunately, completely eliminating any uncertainty about the results of the hypothetical monopolist test is not possible. It is inherent in the need to measure “reasonable” interchangeability. Some of this uncertainty can be reduced, however, when one focuses on competitive effects rather than the line-drawing exercise of market definition.

Furthermore, placing greater weight on market concentration does not eliminate uncertainty. The 1992 Guidelines state: “Where the post-merger HHI exceeds 1800, it will be presumed that mergers producing an increase in the HHI of more than 100 points are likely to create or enhance market power or facilitate its exercise.”33 Merger enforcement data show that this presumption has frequently been overcome.34 Few

33 1992 Guidelines, supra note 2, § 1.51(c).
would favor giving the business community greater certainty by making this presumption irrebuttable.

Third, the tradeoff between simple bright lines and accuracy is inherent in the antitrust review of proposed horizontal mergers. This fundamental tradeoff has been a consideration going back to *Philadelphia National Bank* and the 1968 Guidelines. 35 The 1968 Guidelines are anything but flexible, but I doubt the business community would welcome a return to those Guidelines. Accounting for the real-world business conditions in which a merger takes place is worthwhile, even if doing so means that some simplicity must be sacrificed to achieve greater accuracy in merger enforcement. The second paragraph in the 1982 Guidelines states:

> Although the Guidelines should improve the predictability of the Department’s merger enforcement policy, it is not possible to remove the exercise of judgment from the evaluation of mergers under the antitrust laws. Difficult factual questions arise under the standards stated below, and the Department necessarily will base its decision on the data that are practicably available in each case. Moreover, the standards represent generalizations to which some exceptions are inevitable. 36

Lastly, of specific relevance to businesses considering mergers, the vast majority of mergers reported under the Hart-Scott-Rodino Act (HSR) do not trigger a second request for information from the Agencies. During the ten-year period from Fiscal Year 1999 through Fiscal Year 2008, the percentage of all HSR transactions involving a second request varied annually from a low of 2.1 percent to a high of 4.3 percent. 37 The detailed analysis of competitive effects described in the Guidelines is most relevant to transactions that join together two substantial competitors among a few; these are well less than 5 percent of HSR transactions. Among those mergers, where the Agencies conduct a thorough investigation, experienced practitioners already know that “investigations are intensively fact-driven iterative processes.” 38

HHI greater than 1800 and an increase in the HHI of at least 100, 174, or 17.6 percent, were closed without an enforcement action. Of these 912, 156 involved a post-merger HHI of 1800–2399, and 57 of these, or 36 percent, were closed without an enforcement action. See id.


36 1982 Guidelines, supra note 11, § I.


38 2006 Commentary, supra note 4, at 3.
In practice, economic analyses of mergers often focus on certain quantitative measures, such as prices, costs, market shares, or demand elasticities. But that does not indicate any tendency for DOJ investigations to favor quantitative evidence over qualitative evidence. In practice, a great deal of investigative time and effort is expended to develop qualitative evidence, e.g. by reviewing documents and conducting interviews, and such evidence typically is central to our evaluation of likely competitive effects. The concepts described in the Guidelines inform the gathering and interpretation of this evidence. The 2010 Guidelines, like all of their predecessors, provide a high-level economic framework within which investigative work takes place.

III. UNILATERAL EFFECTS

The biggest shift in merger enforcement between 1992 and 2010 has been the ascendancy of unilateral effects as the theory of adverse competitive effects most often pursued by the Agencies. Prior to 1992, merger enforcement focused primarily on coordinated effects. In recent years, a sizeable majority of DOJ merger investigations have focused on unilateral effects. Along with this pronounced shift in practice has come considerable new economic learning about unilateral effects. This shift in practice and advance in learning regarding unilateral effects was one of the chief reasons we at the DOJ felt that the time had come to update the Guidelines.

Section 6 in the 2010 Guidelines, “Unilateral Effects,” is broken into four parts. These parts describe the distinct modes of analysis that the Agencies use to investigate unilateral effects in different market settings. Sections 6.1 and 6.2 address pricing and bidding competition among suppliers of differentiated products; they are closely related descendents of Section 2.21 from the 1992 Guidelines. Section 6.3 addresses capacity and output for homogeneous products; this part descends from Section 2.22 from the 1992 Guidelines. Section 6.4 addresses innovation and product variety and is entirely new.

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39 For example, an investigation focusing on the extent of direct competition between the merging parties can be usefully structured around diversion ratios even if it is not possible to measure the diversion ratio with precision.

40 This view was widely shared. In 2008, the Antitrust Section of the American Bar Association recommended that the Agencies consider revising the Guidelines (Recommendation 35) to “improve application and understanding of unilateral effects theories” (Recommendation 37), and to “clarify the role of market definition in unilateral effects cases.” (Recommendation 38). ABA SECTION OF ANTITRUST LAW, 2008 TRANSITION REPORT, available at http://www.abanet.org/antitrust/at-comments/2008/11-08/comments- obamabiden.pdf.
A. Pricing of Differentiated Products

Section 2.21 in the 1992 Guidelines dealing with pricing of differentiated products was a major advance over the leading firm proviso in the 1984 Guidelines. This section introduced into the Guidelines two important strands of research from the field of industrial organization economics: (1) pricing competition among suppliers of differentiated products, including the workhorse Bertrand model; and (2) bidding competition in procurement settings. These two strands have been separated in the 2010 Guidelines.

The basic economic principles articulated in Section 2.21 of the 1992 Guidelines are fundamental and should not be controversial. The 2010 Guidelines rely heavily on these basic principles. This key passage from Section 2.21 of the 1992 Guidelines has been retained virtually unchanged:

A merger between firms selling differentiated products may diminish competition by enabling the merged firm to profit by unilaterally raising the price of one or both products above the pre-merger level. Some of the sales lost due to the price rise will merely be diverted to the product of the merger partner and, depending on relative margins, capturing such sales loss through merger may make the price increase profitable even though it would not have been profitable prior to the merger.

The central role of diversion between the products sold by the merging firms is then stressed:

The extent of direct competition between the products sold by the merging parties is central to the evaluation of unilateral price effects. Unilateral price effects are greater, the more the buyers of products sold by one merging firm consider products sold by the other merging firm to be their next choice.

Economists have long measured diversion from one product to another using the cross-elasticity of demand between the two products, and elasticities have been used in antitrust for decades to measure “reasonable interchangeability.” By 1995, DOJ was using the term “diversion ratio,”
to capture this same concept in a more intuitive way. The diversion ratio from Product 1 to Product 2 is defined as the percentage of unit sales lost by Product 1, when its price rises, that are captured by Product 2.45

Section 6.1 in the 2010 Guidelines, like Section 2.21 in the 1992 Guidelines, explains how the Agencies assess the impact of the merger on pricing competition. But the very same concepts can be applied to non-price competition. For example, one can examine how improvements in the quality of a product sold by one merging firm capture sales from a product sold by the other merging firm. The “quality” diversion ratio need not equal the normal (price) diversion ratio.

The focus on diversion in the 1992 Guidelines was impeccable in terms of the underlying economics. But it presented a conundrum: how could this approach be reconciled with the emphasis on market shares found in the case law and perpetuated in the 1992 Guidelines? In a path-breaking article, Robert Willig, one of the primary authors of the 1992 Guidelines, showed the way.46 First, Willig acknowledged the challenge: “On the face of it, this perspective appears to remove consideration of market shares from merger analysis since there are no obvious systematic relationships among market shares and cross-price derivatives of demand.”47 But then Willig identified certain conditions under which “market shares can be accurate indicators of the competitive effect of a merger between producers of differentiated products.”48 The required conditions were subsequently described in the 1992 Guidelines:

The market concentration measures provide a measure of this effect if each product’s market share is reflective of not only its relative appeal as a first choice to consumers of the merging firms’ products but also its relative appeal as a second choice, and hence as a competitive constraint to the first choice. Where this circumstance holds, market concentration data fall outside the safeharbor regions of Section 1.5, and the merging firms have a combined market share of at least thirty-five percent, the Agency will presume that a significant share of sales in the market are accounted for by consumers who regard the products of the merging firms as their first and second choices.49


47 Id. at 300–01.

48 Id. at 301. Willig develops the relevant conditions in the section entitled “Differentiated Product Bertrand Models.” See id. at 299–305.

49 1992 Guidelines, supra note 2, § 2.211 (footnote omitted).
In modern parlance, these are the circumstances in which market shares yield good proxies for diversion ratios.\textsuperscript{50} In particular, as Willig demonstrates, the diversion ratio from Product 1 to Product 2 is proportional to $S_2/(1 - S_1)$, where $S_1$ and $S_2$ are the market shares of Products 1 and 2.\textsuperscript{51} Connecting market shares and unilateral price effects in this way was a theoretical tour de force. But Willig was very careful to emphasize the limitations of this approach. “We shall see that the assumptions are unlikely to be valid in many areas of application where specific information can be developed about product characteristics and about consumer preferences for them. For such applications, merger analysis that focuses exclusively on market shares is likely to go awry.”\textsuperscript{52} Furthermore, even under those special circumstances in which market shares are informative, even Willig, for all his theoretical prowess, could not relate the level of the HHI to diversion ratios.\textsuperscript{53}

Consequently, the treatment in the 1992 Guidelines of unilateral price effects in markets with differentiated products suffered from a mismatch between the basic theory of differentiated product pricing competition, which emphasizes diversion, and the Guidelines’ historical reliance on market shares and HHIs. As one commenter expressed it at the Stanford Workshop, the 1992 Guidelines were like a centaur: the head of differentiated products pricing was grafted onto the body of market definition and market concentration.\textsuperscript{54}

This left the 1992 Guidelines in an uncomfortable state: the link they emphasized between market shares and unilateral price effects rested on a strong assumption about demand (i.e., markets shares are good

\textsuperscript{50} Even in these circumstances, the diversion ratio from Product 1 to Product 2 depends upon the fraction of lost sales of Product 1 that are recaptured by other products in the market, i.e., the market recapture percentage, as well as on the market shares of Products 1 and 2.

\textsuperscript{51} Willig, supra note 46, at 302.

\textsuperscript{52} Id. at 301.

\textsuperscript{53} George Stigler had linked HHIs to the danger of collusion; this required making some rather strong assumptions. See Stigler, supra note 15. Later, the HHI was linked to the welfare effects of changes in outputs in a market for a single homogeneous good. See Keith Cowling & Michael Waterson, \textit{Price-Cost Margins and Market Structure}, 43 \textit{Economica} 267 (1976); Robert E. Dansby & Robert D. Willig, \textit{Industry Performance Gradient Indexes}, 69 \textit{Am. Econ. Rev.} 249 (1979); Joseph Farrell & Carl Shapiro, \textit{Asset Ownership and Market Structure in Oligopoly}, 21 \textit{Rand J. Econ.} 275 (1990). But there is no good theoretical link between the level of the HHI and unilateral price effects with differentiated products.

\textsuperscript{54} “To me the Unilateral Effects standards in the Guidelines are a kind of antitrust centaur in which you have the head of a unilateral effects analysis that has been grafted onto the body of a coordinated effects analysis.” Comment of Dan Wall, Horizontal Merger Guidelines Review Project, Fourth in a Series of Five FTC/DOJ Workshops, Stanford University, at 166 (Jan. 14, 2010), available at http://www.ftc.gov/bc/workshops/hmg/transcripts/100114transcriptstanford.pdf.
proxies for diversion ratios) that often cannot be justified. Willig anticipated this difficulty, writing: “The analysis here also points to the strong need to develop information beyond shares in markets with differentiated products, particularly the relative proximity of the products of the merging firms in the space of salient characteristics.”

Indeed, this is just how practice has evolved since 1992: the DOJ looks at a wide variety of evidence to assess whether the products offered by the merging firms are close substitutes and to measure diversion ratios when possible, sometimes but not always starting with shares in plausibly defined markets.

Spurred by the 1992 Guidelines, and in parallel with major advances in practice, the economic literature relating to unilateral price effects, including the estimation of demand and full merger simulation, developed over the past eighteen years. Many Ph.D. theses have been written about estimating demand systems with differentiated products, and considerable strides have been made in developing simpler approaches that are feasible when data are limited. I cannot possibly do justice to that literature here; in any event, it has been well surveyed quite recently. Suffice it to say that enormous strides have been made in theory and in practice.

As economic learning and practice evolved, the emphasis on market shares found in Section 2.21 of the 1992 Guidelines became less helpful to achieve transparent and accurate merger enforcement using a unilateral-effects theory. For example, in a recently litigated case, the court, citing the relevant passage from the Guidelines, rejected the FTC’s attempt to invoke the 35 percent presumption quoted above.

Recent advances build upon basic theories going back over one hundred years. “Although unilateral effects theories are based on ideas that are quite old as economic theory goes, explicit application of these ideas to merger policy was quite limited prior to the release of the Horizontal Merger Guidelines (1992).” Werden & Froeb, supra note 57, at 43. FTC v. CCC Holdings Inc., 605 F. Supp. 2d 26, 67–72 (D.D.C. 2009).
The 2010 Guidelines modestly update the treatment of unilateral price effects to reflect the substantial changes in economic learning and Agency practice since 1992. Two aspects of that updating are of special significance: (1) reduced emphasis on market shares, and (2) introduction of the “value of diverted sales” as an indicator of upward pricing pressure.

Before turning to those two topics, it is worth highlighting that all of this analysis involving diversion takes as given the set of products being offered and thus does not account for the supply-side responses of repositioning and entry. Although a number of comments criticized the revised Guidelines for purportedly establishing unjustified presumptions about unilateral price effects based on diversion ratios and margins, the Guidelines explicitly state:

A merger is unlikely to generate substantial unilateral price increases if non-merging parties offer very close substitutes for the products offered by the merging firms. In some cases, non-merging firms may be able to reposition their products to offer close substitutes for the products offered by the merging firms. Repositioning is a supply-side response that is evaluated much like entry, with consideration given to timeliness, likelihood, and sufficiency. See Section 9. The Agencies consider whether repositioning would be sufficient to deter or counteract what otherwise would be significant anticompetitive unilateral effects from a differentiated products merger.

This language, however, led to criticism that the revised Guidelines take an overly skeptical approach to repositioning by treating it like entry. Yet the same basic approach can be found in the 1992 Guidelines. The 2006 Commentary observed that in practice repositioning has rarely been a significant factor:

Consideration of repositioning closely parallels the consideration of entry, discussed below, and also focuses on timeliness, likelihood, and sufficiency. The Agencies rarely find evidence that repositioning would

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60 Most of the new points made in Section 6.1 of the 2010 Guidelines can be found in the 2006 Commentary, supra note 4, at 27–28 (section titled “Unilateral Effects Relating to the Pricing of Differentiated Products”).

61 Again, Willig recognized and emphasized this point: “The above discussion proceeded on the implicit assumption that the pattern of demand relationships and products’ characteristics are not subject to endogenous change. Although this may be an accurate assumption in many contexts, in others firms may be readily and quickly able to reposition their products in response to market incentives.” Willig, supra note 46, at 304.


63 “The timeliness and likelihood of repositioning responses will be analyzed using the same methodology as used in analyzing uncommitted entry or committed entry (see Sections 1.3 and 5), depending on the significance of the sunk costs entailed in repositioning.” 1992 Guidelines, supra note 2, § 2:212 n.23.
be sufficient to prevent or reverse what otherwise would be significant anticompetitive unilateral effects from a differentiated products merger. Repositioning of a differentiated product entails altering consumers’ perceptions instead of, or in addition to, altering its physical properties. The former can be difficult, especially with well-established brands, and expensive efforts at doing so typically pose a significant risk of failure and thus may not be undertaken.64

The revised Guidelines recognize that the ease or difficulty of repositioning varies greatly across markets.65

1. Reduced Emphasis on Market Shares

The 2010 Guidelines do not explicitly link diversion ratios to market shares. This reflects experience gained over the years: while market shares are often a useful starting point for assessing diversion ratios, and can indeed be used as proxies for diversion ratios, the DOJ will normally look as well for more direct evidence of diversion ratios. The new language states:

The Agencies consider any reasonably available and reliable information to evaluate the extent of direct competition between the products sold by the merging firms. This includes documentary and testimonial evidence, win/loss reports and evidence from discount approval processes, customer switching patterns, and customer surveys.66

The revised Guidelines go on to state:

Substantial unilateral price elevation post-merger for a product formerly sold by one of the merging firms normally requires that a significant fraction of the customers purchasing that product view products formerly sold by the other merging firm as their next-best choice.67

This differs somewhat from the 1992 Guidelines, which stated:

Substantial unilateral price elevation in a market for differentiated products requires that there be a significant share of sales in the mar-

64 2006 Commentary, supra note 4, at 31.
65 2010 Guidelines, supra note 1, § 6.1. Repositioning is analyzed very similarly in Section 6.2, which covers bargaining and auctions.
66 2010 Guidelines, supra note 1, § 6.1. These ideas were present but less well developed in the 1992 Guidelines, “Information about consumers’ actual first and second product choices may be provided by marketing surveys, information from bidding structures, or normal course of business documents from industry participants.” 1992 Guidelines, supra note 2, § 2.211, n.22. The European Commission follows a similar approach. “When data are available, the degree of substitutability may be evaluated through customers’ preference surveys, analysis of purchasing patterns, estimation of the cross-price elasticities of the products involved, or diversion ratios.” EU Horizontal Merger Guidelines, supra note 29, ¶ 29 (footnotes omitted).
67 2010 Guidelines, supra note 1, § 6.1.
ket accounted for by consumers who regard the products of the merging firms as their first and second choices . . . 68

The revised Guidelines reflect Agency practice, which involves assessing whether the price of any product sold by the merging firms is likely to increase significantly due to the merger. That depends heavily on diversion to products sold by the merging partner, not on any market-wide measure. 69 The central role of diversion between the merging parties is explained this way:

Diversion ratios between products sold by one merging firm and products sold by the other merging firm can be very informative for assessing unilateral price effects, with higher diversion ratios indicating a greater likelihood of such effects. Diversion ratios between products sold by merging firms and those sold by non-merging firms have at most secondary predictive value. 70

Some comments criticized this passage for purportedly downplaying the importance of competition from products offered by non-merging firms. However, that criticism is inapt: if products offered by non-merging firms are close substitutes for a product sold by a merging firm, diversion to those products will normally be high, necessarily depressing the diversion ratio to products sold by the other merging firm. 71 This same point was explicitly made in the 2006 Commentary:

A merger may produce significant unilateral effects even though a non-merging product is the "closest" substitute for every merging product in the sense that the largest diversion ratio for every product of the merged firm is to a non-merging firm’s product. The unilateral effects of a merger of differentiated consumer products are largely de-

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68 1992 Guidelines, supra note 2, § 2.21.
69 In some cases, the economic models used by the Agencies predict significant price increases only for products with relatively few sales. This is most likely to happen if a relatively unpopular product is merging with a popular product that has a larger margin. However, in such cases, the Agencies may conclude that the predicted harm to relatively few customers is not substantial enough to warrant an enforcement action, especially if the merger is expected to generate cognizable efficiencies that will benefit a larger set of customers so customers overall are likely to benefit from the merger. See generally Joshua D. Wright, Comment on the Proposed Update on the Horizontal Merger Guidelines: Accounting for Out-of-Market Efficiencies (May 31, 2010), available at http://www.ftc.gov/os/comments/hmgrevisedguides/548050-00008.pdf.
70 2010 Guidelines, supra note 1, § 6.1.
71 Alison Oldale, Chief Economist at the UK Competition Commission, made this point at the first workshop. "For example, the diversion ratio is a ratio. On the top, you may have just the diversion between the merging parties. But on the bottom, you’ve got the whole world. So, you’ve got the diversion to everything else that might be acting as a constraint. They don’t get lost in the analysis." Fed. Trade Comm’n, Horizontal Guidelines Review Project Workshop, Dec. 3, 2009, at 191, available at http://www.ftc.gov/bc/workshops/hmg/transcripts/091203transcript.pdf.
In a merger joining Products 1 and 2, significant unilateral effects for Product 1 can occur even if Product 2 is not the “closest substitute” overall to Product 1. What these effects require is that a significant percentage of the customers purchasing Product 1 consider Product 2 to be their next second choice. That percentage is captured by the diversion ratio.

DOJ puts far more weight on diversion ratios and margins (see below) than on the HHI level when diagnosing unilateral price effects. This has been the case for many years, and again the 2006 Commentary made clear that HHI levels are of limited predictive value for this purpose:

Indeed, market concentration may be unimportant under a unilateral effects theory of competitive harm. As discussed in more detail in Chapter 2’s discussion of Unilateral Effects, the question in a unilateral effects analysis is whether the merged firm likely would exercise market power absent any coordinated response from rival market incumbents. The concentration of the remainder of the market often has little impact on the answer to that question.73

As noted below, the market shares of the merging firms, and the change in the HHI, are more informative in this context than the level of the HHI.

These changes in practice had left many practitioners uncertain about whether and how the Agencies use HHIs in cases involving unilateral price effects for differentiated products. The revised Guidelines clarify the role of HHIs in such cases:

Diagnosing unilateral price effects based on the value of diverted sales need not rely on market definition or the calculation of market shares and concentration. The Agencies rely much more on the value of diverted sales than on the level of the HHI for diagnosing unilateral price effects in markets with differentiated products.74

The express acknowledgement that HHI levels typically are not very helpful diagnostics in these cases has led to concerns that the valuable screening role played by the HHI thresholds since 1982 has been reduced or lost. In fact, the 2010 Guidelines recognize the importance of these HHI thresholds to help identify mergers that are “unlikely to have

72 2006 Commentary, supra note 4, at 28.
73 Id. at 16.
74 2010 Guidelines, supra note 1, § 6.1.
adverse competitive effects and ordinarily require no further analysis."75 Indeed, the 2010 Guidelines not only retain HHI thresholds but raise them. DOJ continues to apply the HHI thresholds to all horizontal mergers.76 Of course, HHIs can only be calculated after a relevant market has been defined, so uncertainty about the scope of the relevant market necessarily creates uncertainty about applicable levels and changes in the HHI. Below, I discuss market definition in cases involving differentiated products.

The combined shares of the merging firms, and the change in the HHI, can be useful and informative metrics in unilateral effects cases, and these measures are used by the Agencies. If diversion is proportionate to market share, the diversion from Product 1 to Product 2 is proportionate to \( S_2/(1-S_1) \), which can be approximated as \( S_2(1+S_1) \) if \( S_1 \) is not too large.77 Approximating the diversion ratio from Product 2 to Product 1 in the same way, and adding up the two diversion ratios, gives \( S_1 + S_2 + 2S_1S_2 \) which equals the combined share of the merging firms plus the change in the HHI. Unilateral price effects are unlikely if the change in the HHI is less than 100, which corresponds to a merger between firms with market shares of 5 percent and 10 percent.

Nonetheless, the revised Guidelines do not retain the presumption that the merging firms are significant direct competitors if their combined market share is at least 35 percent. This presumption was dropped, for four reasons. First, the 1992 Guidelines did not provide a specific basis for the 35 percent figure. Evidently, it was taken from the 35 percent figure used in the leading firm proviso since 1982. But that proviso was based on a very different model and theory: the dominant firm/competitive fringe model in a market for a homogeneous good. Second, as practice evolved, the 35 percent presumption was often invoked as a safe harbor, with merging parties frequently asserting that,  

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75 Id. § 5.3.
76 Merging parties generally emphasize HHIs when they are low and downplay HHIs when they are high. This perspective is reflected in the comments filed by the ABA Antitrust Section, which applauds the Agencies for expanding the HHI-based safe harbor zones while urging the Agencies to disavow any presumptions based on high HHIs. See ABA Section of Antitrust Law, HMG Revision Project—Comment, Project No. P092900, at 12 (June 4, 2010), available at http://www.ftc.gov/os/comments/hmgrevisedguides/548050-00026.pdf. The 2010 Guidelines, like their predecessors, are consistent in placing some weight on HHIs, be they low or high.
77 The ratio of the approximation to the precise value is \((1 + S_1)(1 - S_1)\) which equals \((1 - S_1^2)\), so the approximation is less than the actual value. If Firm 1’s market share is 10 percent, \( S_1 = 0.1 \) and the approximation is 99 percent of the actual value. If Firm 1’s market share is 20 percent, \( S_1 = 0.2 \) and the approximation is 96 percent of the actual value. If Firm 1’s market share is 30 percent, \( S_1 = 0.3 \) and the approximation is 91 percent of the actual value.
according to the Guidelines, there could be no substantial unilateral price effects if their combined share of the relevant market was less than 35 percent. In fact, the 1992 Guidelines contain no such safe harbor.78 Nor would one be justified: a merger combining two products that are close substitutes can lead to substantial unilateral price increases for those products even if their combined market share is less than 35 percent. Third, the presumption could only properly be invoked if market shares are a reasonable proxy for diversion ratios. As discussed above, DOJ often uses market shares to assess diversion, and higher shares in a properly defined relevant market do generally go along with elevated concern about unilateral price effects. But we also look for more direct evidence of diversion. Fourth, as emphasized in this article, economic theory relates unilateral price effects with differentiated products more directly to diversion ratios and margins than to the combined market share of the merging firms.

2. The Value of Diverted Sales

The 2010 Guidelines introduce the “value of diverted sales” into the analysis of unilateral price effects with differentiated products:

Adverse unilateral price effects can arise when the merger gives the merged entity an incentive to raise the price of a product previously sold by one merging firm and thereby divert sales to products previously sold by the other merging firm, boosting the profits on the latter products. Taking as given other prices and product offerings, that boost to profits is equal to the value to the merged firm of the sales diverted to those products. The value of sales diverted to a product is equal to the number of units diverted to that product multiplied by the margin between price and incremental cost on that product.79

The basic economics underlying the “value of diverted sales” concept are not new. Suppose that the merger brings under common ownership Product 1, formerly owned by Firm 1, and Product 2, formerly owned by Firm 2. One key question is whether the merger is likely to lead to a significant price elevation for Product 1?80 As stressed above, repositioning and entry are not considered at this point in the analysis, which takes as given the set of competing products offered by non-merging firms. One can also take as given the prices charged by non-merging

78 “Section 2.2 of the Guidelines does not establish a special safe harbor applicable to the Agencies’ consideration of possible unilateral effects.” 2006 Commentary, supra note 4, at 26.
79 2010 Guidelines, supra note 1, § 6.1.
80 This question can then be repeated for Product 2 and other products owned by the merging firms.
rivals for their products. Holding these prices fixed typically will lead to an under-estimate of the magnitude of the post-merger price change.81

With these simplifications, the central question can be posed very specifically: “Taking as given all other products and their prices, is the profit-maximizing price for Product 1 significantly higher for a firm that owns both Product 1 and Product 2 than it was for Firm 1, which owns just Product 1?” The answer to this question depends entirely on (a) how the demand for these two products varies as their prices rise above pre-merger levels, and (b) their pre-merger margins.82

As discussed in more detail below, this is precisely the same question posed by the hypothetical monopolist test to see if Products 1 and 2 form a relevant market. This very tight connection between unilateral price effects with differentiated products and market definition was not clear in earlier Guidelines. The Guidelines now clarify this relationship by explaining in more detail how the hypothetical monopolist test works with differentiated products.83

As a first step to answering this question, it is instructive to simplify even further by holding fixed the price of Product 2 and asking how common ownership of Product 2 changes the pricing incentives for Product 1, starting at pre-merger prices. Studying these incentives requires far less information than estimating the profit-maximizing price increase for Product 1.

To see how common ownership changes incentives, it is a bit easier to think in terms of the incentives to sell more units of Product 1 (the reverse of raising the price of Product 1). Owning Product 2 creates a disincentive to sell more units of Product 1. Suppose that for every four extra units sold of Product 1 by lowering its price, one fewer unit of

81 Rivals usually have an incentive to raise the prices of their products in response to the higher demand they face when the merged firm raises the prices for its products. As Willig puts it: “rival nonparties have incentives to raise their prices in response.” Willig, supra note 46, at 299 (citing Raymond Deneckere & Carl Davidson, Incentives to Form Coalitions with Bertrand Competition, 16 RAND J. ECON. 473 (1985)). Therefore, accounting for rival pricing responses magnifies the predicted price increases (or decreases). Merger simulation models typically account for such responses. “These models often include independent price responses by non-merging firms.” 2010 Guidelines, supra note 1, § 6.1.

82 Strictly speaking, one needs to measure the marginal cost of Products 1 and 2 at output levels in the vicinity of pre-merger levels. If marginal cost is constant within this range of output, knowing pre-merger marginal cost is sufficient. The assumption of constant marginal cost is commonly made, and I make it here. Modifying the analysis to account for non-constant marginal cost is not difficult in principle and can be important in practice.

83 One way the revised Guidelines do this is by linking together Example 5 on market definition with Example 19 on unilateral price effects. Market definition with differentiated products is addressed below.
Product 2 is sold. This corresponds to a diversion ratio of 25 percent. The higher the diversion ratio, the greater the disincentive to sell units of Product 1 created by the merger. So far so good, as per the 1992 Guidelines. The logical—and unavoidable—next step is to ask how cannibalizing sales of Product 2 affects the merged firm’s profits from selling more units of Product 1. Lost unit sales of Product 2 only affect the merged firm’s profits to the extent that those sales were contributing to profits, i.e., to the extent that price exceeds marginal cost for Product 2. This directs our attention to the gap between price and marginal cost for Product 2. This is just arithmetic.84

Suppose that Products 1 and 2 each sell for $100,000, and the marginal cost of each is $60,000, so each unit sold contributes $40,000 towards covering fixed costs and earning profits. For every four extra units sold of Product 1, one unit of Product 2 is cannibalized, leading to a lost contribution of $40,000. Thus, every extra unit sold of Product 1 reduces Product 2’s contribution by $10,000. Combining the ownership of Products 1 and 2 thus creates a $10,000 per-unit disincentive to sell units of Product 1. In economic terms, the merged entity bears a $10,000 per-unit opportunity cost not borne by Firm 1.85

Moving beyond this specific numerical example, the per-unit opportunity cost of selling Product 1 that is borne (internalized) by the merged firm but not Firm 1 is equal to $D_{12}(P_2 - C_2)$, where $D_{12}$ is the diversion rate from Product 1 to Product 2, $P_2$ is the price of Product 2, and $C_2$ is the marginal cost of Product 2. The opportunity cost is equal to the multiplicative product of the diversion ratio and the margin.86 Neither the

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86 Nearly twenty years ago, Willig showed that the multiplicative product of the diversion ratio and the margin was the key driver of unilateral effects:

Thus, to the first order, the incentive to raise the price of good 1 following a merger with the seller of good 2 is greater the larger the product of the markup on 2 and the derivative of the demand for 2 with respect to the price of 1. This cross-price derivative is meaningfully scaled in relation to the absolute value of
diversion ratio nor the margin operates alone to generate upward pricing pressure.

These ideas are at least twenty years old, as the Willig reference shows, and are not new at DOJ. When I served as Deputy Assistant Attorney General for Economics in 1995 I wrote:

Roughly speaking, a valuable index of the potential anticompetitive unilateral effects is obtained by multiplying the Diversion Ratio by the Gross Margin. Any danger of a unilateral price increase may be alleviated by product repositioning, entry, or efficiencies. Nonetheless, the Diversion Ratio and the Gross Margin are the key variables in the demand-side portion of the analysis.87

For example, the DOJ’s 1997 challenge to the proposed merger between Vail Resorts and Ralston Resorts noted the central role of diversion ratios and margins in unilateral price effects:

This unilateral effect will be larger as the recapture rate (which is sometimes called the “diversion ratio,” see infra note 4) is larger, as the margin earned on recaptured customers is higher, and as the customers who leave the merging firms in response to a price increase are fewer (in technical terms, the lower the “own price elasticity”).88

The 2010 Guidelines move beyond diversion ratios, directing attention to the “value of diverted sales.” The “value of diverted sales” incentive measure is constructed from the multiplicative product of a diversion ratio and a margin.

Consider a small price increase on Product 1, which we denote by $\Delta P_1$. Holding fixed all prices other than $P_1$, this will cause the unit sales of Product 1 to fall by some amount, call it $\Delta X_1$. Some of those lost sales will be diverted to Product 2, call them $\Delta X_2$. The revised Guidelines define the value of sales diverted to Product 2 by the price increase for Product 1 as “the number of units diverted to that product multiplied by the margin between price and incremental cost on that product.”89 The value of diverted sales associated with the postulated price increase for Product 1 thus is given by $V \equiv \Delta X_2 \cdot (P_2 - C_2)$.

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The value of diverted sales is usefully measured in proportion to the reduction in unit sales of Product 1 resulting from the price increase, i.e., $\Delta X_1$. On this per-unit basis, the value of diverted sales is equal to
g$$\frac{\Delta X_2}{\Delta X_1} (P_2 - C_2).$$
This equals the opportunity cost term, $D_{12}(P_2 - C_2)$ that emerged inexorably out of the basic logic of unilateral price effects.

The next and final step in this line of reasoning is to scale this opportunity cost in proportion to the price of Product 1. This gives $D_{12}(P_2 - C_2) / P_1$, which is a gross upward pricing pressure index for Product 1. We label this very useful index as

g$$GUPI_{1} = \frac{P_2 - C_2}{P_1}.$$ 

The Guidelines now provide a condition under which unilateral price effects are unlikely:

If the value of diverted sales is proportionately small, significant unilateral price effects are unlikely. . . . For this purpose, the value of diverted sales is measured in proportion to the lost revenues attributable to the reduction in unit sales resulting from the price increase. Those lost revenues equal the reduction in the number of units sold of that product multiplied by that product’s price.¹⁰¹

This condition corresponds to a low value of the GUPPI. As noted above, the value of diverted sales is equal to $V \equiv \Delta X_2 (P_2 - C_2)$. The lost revenues attributable to the reduction in unit sales of Product 1 are given by $L \equiv \Delta X_1 \times P_1$. Measuring the value of diverted sales in proportion to the lost revenues gives

g$$\frac{V}{L} = \frac{\Delta X_2 (P_2 - C_2)}{\Delta X_1 \times P_1} = D_{12} \frac{P_2 - C_2}{P_1},$$

which equals $GUPI_{1}$. Denoting the relative margin on Product 2 as $M_2 = (P_2 - C_2) / P_2$, the gross upward pricing pressure index on Product 1 can be expressed as


⁹¹ 2010 Guidelines, supra note 1, § 6.1, § 6.1 n.11.
If the two products have equal prices, this index becomes simply $GUPPI_1 = D_{12} M_2$. 

Summarizing, the revised Guidelines direct attention to the disincentive created by the merger to sell additional units of Product 1 if these cannibalize unit sales of Product 2. This disincentive is measured as an opportunity cost borne by the merged firm for selling Product 1. That opportunity cost, scaled in comparison to the price of Product 1, is equal to the multiplicative product of the diversion ratio to Product 2 and the margin on Product 2. Unilateral price effects for Product 1 are unlikely if this measure is small.

Focusing in this way on how the merger changes pricing incentives achieves two important goals. First, the treatment of unilateral price effects in the Guidelines now rests on a rock solid economic foundation.\textsuperscript{92} The economic principles used are extremely basic and robust: (a) firms account for opportunity costs (cannibalization) when pricing and promoting product lines containing substitute products, and (b) higher costs tend to lead to higher prices.\textsuperscript{93} Second, the Guidelines now identify circumstances under which unilateral price effects for a given product are unlikely: when the opportunity cost term for that product is small as a fraction of that product’s price. Because the gross upward pricing pressure index is so well grounded in basic economics, a quasi-safe-harbor based on this index does not suffer from the mismatch between the economic logic of unilateral price effects and a quasi-safe-harbor based on the HHI level.\textsuperscript{94}

This approach also indicates how to incorporate efficiencies into the analysis. For example, merger-specific reductions in the marginal cost of Product 1 create an incentive to lower the price of Product 1. In particular, efficiencies create downward price pressure that can reduce or reverse the incentive to raise price just discussed. One of the attractive

\textsuperscript{92} In his comment, Robert Willig writes: “First, the value-of-diverted-sales is a potentially powerful new tool with a distinguished pedigree in the economics literature and solid support in professional economic logic.” Robert Willig, Public Comments on the 2010 Draft Horizontal Merger Guidelines 3 (June 4, 2010), available at http://www.ftc.gov/os/comments/hmgrevisedguides/548050-00015.pdf.

\textsuperscript{93} Some comments mistakenly believe that the appearance of the margin on Product 2 in the value of diverted sales measure reflects an assumption about the relationship between the margin on Product 2 and the elasticity of demand for Product 2. No such assumption is required for the arithmetic to operate as described above.

\textsuperscript{94} Additionally, the quasi-safe-harbor based on GUPPI is far better grounded in economics than was the 35 percent presumption in the 1992 Guidelines.
features of the revised Guidelines is that efficiencies can easily and naturally be integrated into the analysis. One can directly compare any merger-specific reduction in marginal cost for Product 1 with the opportunity cost due to cannibalization.\textsuperscript{95} A merger thus generates net upward pricing pressure for Product 1 if the opportunity cost exceeds the efficiencies for that product.\textsuperscript{96} The value of diverted sales measure used in the Guidelines, scaled as GUPPI, indicates how large the marginal cost savings must be on Product 1, measured as fraction of the price of Product 1, for there to be no net upward pricing pressure on Product 1, given the price of Product 2.

The value of diverted sales, taken alone, does not purport to quantify the magnitude of any post-merger price increase. Rather, as the Guidelines state, it "can serve as an indicator of the upward pricing pressure on the first product resulting from the merger."\textsuperscript{97} This is an important distinction not appreciated in some comments. In Appendix A, I elaborate on this point. The value of diverted sales is a measure of the extra (opportunity) cost the merged firm bears in selling units of Product 1. Higher costs give the merged firm an incentive to raise the price of Product 1. But further analysis is needed to determine how that cost increase translates into a price increase. That depends upon the rate at which costs are passed-through to prices, which in turn depends upon the curvature of the demand curve.\textsuperscript{98} Pass-through rates are important

\begin{itemize}
  \item \textsuperscript{95} This comparison depends upon the pre-merger mode of behavior. The analysis in the remainder of this paragraph is clearest if the firms set prices independently pre-merger, as in the Bertrand model of differentiated product oligopoly. If a different mode of behavior prevails pre-merger, a modified version of the diversion ratio applies. If there is substantial pre-merger coordination between the merging firms, which can involve nothing more than parallel accommodating conduct, unilateral effects will tend to be smaller, because there is less competition between the two firms to be lost due to the merger. In that situation, the Agencies may instead pursue a theory of coordinated effects.
  
  \item \textsuperscript{96} The details are worked out in Farrell & Shapiro, \textit{Antitrust Evaluation of Horizontal Mergers}, supra note 85 (building upon O'Brien & Salop, supra note 84, and Gregory J. Werden, \textit{A Robust Test for Consumer Welfare Enhancing Mergers Among Sellers of Differentiated Products}, 44 J. INDUS. ECON. 409 (1996) [hereinafter \textit{A Robust Test}]).
  
  \item \textsuperscript{97} 2010 Guidelines, supra note 1, § 6.1.
  
  \item \textsuperscript{98} The basic relationship between the pass-through rate and the curvature of demand is derived in Jeremy I. Bulow & Paul Pfleiderer, \textit{A Note on the Effect of Cost Changes on Prices}, 91 J. POL. ECON. 182 (1983). The pass-through rate is lower, the more sharply demand falls off as price goes up. For a recent, deep analysis of pass-through rates in oligopoly, see E. Glen Weyl & Michal Fabinger, \textit{Pass-Through as an Economic Tool} (Oct. 2009) (unpublished manuscript), available at http://www.people.fas.harvard.edu/~weyl/Pass-through_10_09.pdf. In his public comment, Dennis Carlton notes that the relationship between upward pricing pressure and the equilibrium post-merger price increase for a given product depends upon the pass-through rate for that product as well as feedback effects arising due to changes in the prices and costs of other products. Dennis W. Carlton, Comment on Department of Justice and Federal Trade Commission’s Proposed Horizon-
but can be difficult to estimate empirically. If the elasticity of demand is constant for small price changes, the pass-through rate is greater than one. If unit sales are equally sensitive to small price increases and decreases, demand is linear and the pass-through rate is one-half. In the extreme, if demand were sharply kinked at pre-merger prices, meaning buyers are far more sensitive to price increases than price decreases, the pass-through rate would be low, and even a large incentive to raise price would not translate into a significant price increase. Kinks are implausible when demand comes from multiple diverse buyers; kinks also generally lack empirical support.99

The value of diverted sales is an excellent simple measure for diagnosing or scoring unilateral price effects, but it cannot capture the full richness of competition in real-world industries. Indeed, as stressed above, all of the quantitative methods discussed here must be used in conjunction with the broader set of qualitative evidence that the Agencies assemble during a merger investigation.

A thorough analysis often must do more than just quantifying how the merger changes pricing incentives. Further information about demand is needed, and additional analysis is required, to translate these incen-

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99 The theoretical point was made nicely by Hotelling: [A] discontinuity, like a vacuum, is abhorred by nature. More typical of real situations is the case in which the quantity sold by each merchant is a continuous function of two variables, his own price and his competitor’s. Quite commonly a tiny increase in price by one seller will send only a few customers to the other.

Harold Hotelling, Stability in Competition, 39 Econ. J. 41, 44 (1929).

Kinked demand would imply that small changes in costs are not passed through at all to prices, but this is inconsistent with the extensive empirical literature on pass-through rates. See Weyl & Fabinger, supra note 98, at 13–14. For example, Besanko, Dubé, and Gupta study retail pass-through rates, finding that “[o]wn-brand pass-through rates are, on average, more than 60% for 9 of 11 categories.” David Besanko, Jean-Pierre Dubé & Sachin Gupta, Own-Brand and Cross-Brand Retail Pass-Through, 24 Mktg. Sci. 123, 125 (abstract) (2005). Scheffman and Simons assert that kinks in demand are common for consumer products, but Werden explains theoretically why kinks are implausible and reviews the empirical literature, which does not find kinks. See David Scheffman & Joseph Simons, Unilateral Effects for Differentiated Products: Theory, Assumptions and Research, Antitrust Source, Apr. 2010, http://www.abanet.org/antitrust/at-source/10/04/Apr10-Scheffman4-14f.pdf; Gregory Werden, Unilateral Effects with Differentiated Products: A Response to Scheffman and Simons, Antitrust Source, June 2010, http://www.abanet.org/antitrust/at-source/10/06/Jun10-Werden6-24f.pdf; see also Kevin M. Murphy & Robert H. Topel, Critical Loss Analysis in the Whole Foods Case, Global Competition Pol’y, Mar. 2008, at 5 (“It is true that this ad hoc pattern of consumer responses would reconcile things, but what is the evidence?”). Even if there were a kink just at the pre-merger prices, there is unlikely to be a kink at other price levels, and those prices may well become the “but-for” prices in the future, e.g., if costs change.
tives into predictions of post-merger price increases. To accomplish this, DOJ economists and economists working for merging parties often undertake merger simulation exercises. The revised Guidelines, for the first time, identify merger simulation as a methodology used by the Agencies. In some cases, the DOJ uses merger simulation methods to diagnose unilateral price effects. Before using the output of any merger simulation model to actually predict the magnitude of the post-merger price increase, DOJ economists check the model’s output for robustness and consistency with other evidence. We also consider repositioning, entry, and efficiencies.

The competition authorities in the United Kingdom have been using very closely related techniques for the past five years to diagnose unilateral price effects. In its analysis of the proposed acquisition by Somerfield of 115 stores from William Morrison Supermarkets, the UK Competition Commission (CC) computed “illustrative post-merger price rises” based on diversion ratios and margins.

As set out in Appendix D, illustrative ‘post-merger price rises’ can be calculated on the basis of the diversion ratio and the margin. We did not seek to use the formulae directly to predict post-merger price rises, because our concerns are more widely with a deterioration in PQRS [price, quality, and range of service] over time, as a result of reduced competitive constraints, rather than just an increase in price. However, we did regard that approach as providing important guidance on how to combine margin and diversion ratio data to evaluate the relative lessening of competitive constraints in different stores.

Neither high diversion ratios nor high margins in isolation need indicate that a merger has potential anticompetitive effects. Rather, it is the combination of a high diversion ratio and high margins (with other qualitative factors relevant to a highly complex market—see paragraph 7.16) that can indicate a loss of competition; where margins are high, firms face little competitive constraint; and where diversion ratios are high, an acquiring firm may be removing what little competitive constraint it faces. The value in the illustrative price rise is in combining diversion ratios and margins in one measure.

The UK Office of Fair Trading (OFT) now applies a rebuttable presumption based on combining diversion ratios and margins:

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100 Appendix A discusses how some highly simplified merger simulation methods relate to diversion ratios, margins, and the value of diverted sales.

Accordingly, the combination of gross margin data and diversion ratios is a valuable measure of the change in incentives brought about by a merger. Due to the general probative value of this combination of evidence, the OFT applies a rebuttable presumption that a merger between firms with (i) high margins and (ii) significant diversion ratios between them raises a realistic prospect of a substantial lessening of competition through unilateral effects.\footnote{UK Office of Fair Trading, Anticipated Acquisition of the Online DVD Rental Subscription Business of Amazon Inc. by LOVEFiLM International Limited ¶ 30, No. ME/3534/08 (2008), available at http://www.oft.gov.uk/OFTwork/mergers/decisions/2008/LOVEFiLM. The OFT has subsequently applied this presumption in the Home Retail Group/Focus merger, the Co-operative Group/Somerfield merger, and in the William Morrison Supermarkets/Co-operative Group merger. UK Office of Fair Trading, Completed Acquisition by Home Retail Group plc of 27 Leasehold Properties from Focus (DIY) Ltd ¶ 62, ME/3427/07 (2008); UK Office of Fair Trading, Anticipated Acquisition by Co-operative Group Limited of Somerfield Limited ¶¶ A.11–A.13, ME/3777/08 (2008); UK Office of Fair Trading, Completed Acquisition by Wm Morrison Supermarkets plc of 30 Stores from Co-operative Group Limited ¶ 23, CR/34/09 (2009).}

Consistent with these cases, the September 2010 UK Merger Assessment Guidelines emphasize diversion ratios and margins and refers to the illustrative price rise methodology.\footnote{UK Competition Comm’n & Office of Fair Trading, Merger Assessment Guidelines, ¶¶ 5.4.6–5.4.12 (Sept. 2010), available at http://www.oft.gov.uk/shared_oft/mergers/642749/OFT1254.pdf.} Likewise, the European Commission’s Guidelines on the Assessment of Horizontal Mergers state: “High pre-merger margins may also make significant price increases more likely.”\footnote{EU Horizontal Merger Guidelines, supra note 29, ¶ 28.}

Some observers have questioned whether these techniques are practical, given the need to measure diversion ratios and margins, suggesting that they are far more complex than simply measuring HHIs.\footnote{When the 1982 Guidelines were first released, critics questioned whether the hypothetical monopolist test was practical. Techniques soon developed for implementing the test, which has since been embraced by the courts. Werden characterizes the criticism as “dead wrong.” See Werden, Hypothetical Monopolist Paradigm, supra note 13, at 253, 286.} These concerns are easily answered.

First and foremost, DOJ economists and economists working for the merging parties have been measuring diversion and margins for many years. Margins are used in critical loss analysis and are an essential element of market definition under the hypothetical monopolist test, as discussed in more detail below. Diversion ratios have been central to unilateral effects cases since 1992. Yes, there are well-known pitfalls in measuring margins using accounting data, but DOJ economists are well aware of these pitfalls and skilled at overcoming them when the data...
permit. Second, as noted above, in addition to U.S. agency experience, the UK competition authorities have been using these techniques for the past five years. Third, the documents of merging parties can be informative regarding diversion ratios and margins. Firms often are keenly interested in identifying the rivals to which they lose business, or from which they can gain business. Businesses are far more likely to ask these questions in their day-to-day operations than they are to ask how customers would respond to a price increase by a hypothetical monopolist. Margins are also central to business decisions. Margins are an essential element of pricing decisions, and the return on a marketing campaign that attracts new customers depends directly on the price/cost margins that will be earned on those customers. Indeed, in suitable cases, where reasonably reliable measurement of diversion ratios and margins is possible, these techniques can offer a lot. But they are not meant to displace other methods in situations where diversion ratios and margins cannot be measured with reasonable reliability.

This is a good point to address another common criticism of unilateral effects theory: the claim that unilateral effects models “always predict a price increase” and thus are unsuitable for merger enforcement. This assertion is incorrect. First, the criticism ignores efficiencies, repositioning and entry. Efficiencies generate downward pricing pressure that may outweigh the upward pricing pressure, particularly when repositioning and entry mitigate the upward pricing pressure. Second, the criticism erroneously assumes that the Agencies mechanically run a merger simulation model without examining other evidence or exercising judgment. In fact, the Agencies put real weight on these models only when they are reliable and consistent with other evidence. The Guidelines emphasize that the Agencies use qualitative and quantitative evidence together. If a merger simulation model “predicts” a tiny price increase, that may alleviate DOJ concerns—precisely because DOJ understands that these models typically generate at least some post-merger price increase in the absence of any efficiencies. The Guidelines reflect this by stating that unilateral price effects are unlikely if the value of diverted sales is proportionately small. The UK Competition Commission made this same point very nicely:

106 Academic researchers are often unable to obtain good estimates of marginal cost using publicly available accounting data. DOJ economists and economists working for merging firms often can estimate marginal costs using detailed, proprietary information that is available through the HSR discovery process but unavailable to academic researchers.

107 See Oldale, supra note 71, at 191–94.
We note that the analytical process described above will always produce a positive predicted price rise, for any merger in which the diversion ratio exceeds zero and firms are making positive margins. In practice, some mergers clearly do not result in an SLC [substantial lessening of competition]. It seems to us likely, in this inquiry, where the diversion ratio is low and the illustrative price increase is low (because margins are low), there is no SLC: that any lessening of competition is non-existent or insubstantial. We would expect no (or at least no substantial) price rises or reductions in PQRS where this is so. It should not be assumed that the ‘predicted price rises’, below 5 per cent, in these cases represent real price rises that are in some way ‘acceptable’ to the [UK Competition Commission].

Although this criticism often is coupled with an apparent preference for HHI analysis, the same criticism could be made about economic models involving the HHI.

For all of these reasons, DOJ investigations mainly use the GUPPI and merger simulation models to provide an indication—not a precise prediction—of whether a merger is likely to cause significant unilateral price effects. Both methods are used in conjunction with other evidence.

B. BARGAINING AND AUCTIONS

The substantial majority of merger investigations at the DOJ involve firms that sell intermediate goods: the customers of the merging firms are themselves businesses, not final consumers. Indeed, in many cases the buyers are themselves large firms; below, I discuss powerful buyers. In the majority of cases I have worked on as Economics Deputy, the merging firms negotiate prices (and other terms and conditions) with their customers. As Section 2.2.2 points out, testimony from well-informed customers can be especially important in these cases.

Section 6.2 in the revised Guidelines, “Bargaining and Auctions,” addresses these very common situations. This section draws heavily from the 2006 Commentary, which contains separate sections on “Unilateral Effects Relating to Auctions” and “Unilateral Effects Relating to Bargaining,” including numerous examples.

Price discrimination is quite common in these settings. Suppliers often have considerable information about individual customers, including information about customers’ needs or options, customers’ switch-

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109 2006 Commentary, supra note 4, at 31–34.
110 Id. at 34–36.
ing costs, and the costs of serving different customers. DOJ often investigates to determine whether certain types of customers, or certain individual customers, are likely to be harmed by a merger. Section 3 in the revised Guidelines, “Targeted Customers and Price Discrimination,” has been added to reflect the importance of these situations in practice.

The Agencies analyze unilateral effects in bargaining and auction situations using similar approaches to those just discussed for differentiated products. To see the connection, consider a situation in which suppliers submit sealed bids to win a particular piece of business. The customer picks the most attractive bid, accounting for price, other terms and conditions, and differences among the suppliers in the products and services they offer, their reputation, etc. As a matter of formal economics, this is very similar to the situation just discussed, where suppliers set prices and each of many customers each picks his or her preferred product. In the bidding setting, each supplier tries to judge the relationship between its bid and the probability it will win the business. In the consumer products setting, each supplier tries to judge the relationship between its price and the number of consumers who pick its product. Either way, the supplier sees a negative relationship between its price and the number of units it expects to sell.

The details of unilateral effects analysis depend on the auction format. For example, in the classic English (open-outcry) procurement auction to provide specified goods or services, bidders publicly offer lower and lower prices to provide the required goods or services until the bidding stops. The equilibrium outcome for such an auction is for the bidder with the lowest cost to win at a price equal to the cost of the next most efficient bidder. In this setting, a merger between the two lowest-cost bidders will lead to a price increase, with the size of the price increase equaling the difference in cost between the less efficient merging firm and the next most efficient bidder. This opens up the distinct possibility that a merger will harm some customers—those for whom the merging firms are the two lowest cost suppliers—but not others.

Section 6.2 identifies the key factors that the Agencies consider in bidding and auction settings:

Anticompetitive unilateral effects in these settings are likely in proportion to the frequency or probability with which, prior to the merger, one of the merging sellers had been the runner-up when the other

\[111\] For an outstanding discussion of competition in bidding markets, emphasizing that the same principles apply to these settings as to “ordinary markets,” see Paul Klemperer, UK Competition Comm’n, Bidding Markets (June 2005), available at http://www.competition-commission.org.uk/our_role/analysis/bidding_markets.pdf.
won the business. These effects also are likely to be greater, the greater advantage the runner-up merging firm has over other suppliers in meeting customers’ needs. These effects also tend to be greater, the more profitable were the pre-merger winning bids. All of these factors are likely to be small if there are many equally placed bidders.\footnote{2010 Guidelines, supra note 1, § 6.2. See also EU Horizontal Merger Guidelines, supra note 29, ¶ 29.}

The first of these elements is the bidding analog of the diversion ratio. DOJ economists, and economists for merging parties, have long been working with win/loss data and other bidding and auction data to assess how often one merging firm is the runner-up when the other merging firm wins the business. We also routinely try to assess the second element—the magnitude of the advantage the runner-up merging firm has over rival suppliers. This advantage is likely to be larger, the more highly differentiated are the goods and services offered by the various suppliers. High margins tend to go along with such differentiation.

Customers sometimes structure their procurements in multiple rounds, down-selecting to just two or three suppliers for the final round. This is especially common when the procurement process itself is costly, e.g., because the suppliers must work closely with the customer to understand its needs and to prepare customized bids. In these circumstances, the frequency with which the merging firms met each other as finalists tends to be quite important to our analysis. Normally, when the merging firms are finalists, the customer benefits from competition between them. In that circumstance, we typically seek to determine whether replacing one of the merging firms with another supplier as a finalist would leave that customer in a less favorable negotiating position. Merging firms often claim that certain non-merging firms can and will offer an equally good alternative to customers. Customer evidence can be especially valuable in assessing this claim. There can be some tension between this claim and the presence of significant supplier differentiation. We may test this claim with evidence from procurement events in which the merging firms competed as finalists against these non-merging firms. If they really do offer very close substitutes, one would expect to see relatively low margins in those bidding situations.

C. INNOVATION AND PRODUCT VARIETY

The 1992 Guidelines have been widely criticized for putting an undue focus on pricing competition and giving short shrift to innovation. While this is not an entirely fair characterization, arguably the 1992 Guidelines gave the impression that the Agencies did not pay sufficient
attention to competition in product quality, service, or innovation. There was a consensus that new Guidelines should do more to acknowledge the importance of non-price competition, especially innovation competition, and to explain how the Agencies incorporate non-price competition into their merger analysis.

The revised Guidelines place far greater emphasis on non-price competition. For expositional reasons, this was done “globally” in the introduction:

Enhancement of market power by sellers often elevates the prices charged to customers. For simplicity of exposition, these Guidelines generally discuss the analysis in terms of such price effects. Enhanced market power can also be manifested in non-price terms and conditions that adversely affect customers, including reduced product quality, reduced product variety, reduced service, or diminished innovation. Such non-price effects may coexist with price effects, or can arise in their absence. When the Agencies investigate whether a merger may lead to a substantial lessening of non-price competition, they employ an approach analogous to that used to evaluate price competition.\footnote{Id. § 1. The European Commission also considers non-price competition, including whether a merger will lead to a unilateral reduction in innovation. See EU Horizontal Merger Guidelines, supra note 29, ¶ 38.}

The Agencies are well aware of the importance of non-price competition, and especially the enormous importance over the long run of innovation competition in generating consumer benefits. At DOJ, we routinely consider non-price aspects of competition, including service, product quality, and innovation. In some cases, such as over-the-air radio and various Internet-based services and content, the product is free to consumers so competition to attract consumers takes place entirely on non-price dimensions.

Section 6.4, “Innovation and Product Variety,” explains in general terms how the Agencies evaluate whether a merger is likely to significantly harm customers by retarding innovation or reducing product variety. The analysis of innovation comes in two parts.

The first part looks at the shorter-term impact of the merger on the introduction of new products. This part focuses on whether new products being developed by one merging firm will cannibalize significant profits from products sold by the other merging firm. This analysis is much like that in Sections 6.1 and 6.2, in that it focuses on diversion and cannibalization of profits, but the business decisions here involve product introduction, not pricing.
The second part considers the longer-term impact of the merger on innovation. This usually involves looking beyond the products currently being offered, and perhaps even those being developed. This part of the analysis focuses more on the firms’ R&D plans and capabilities. Longer-term effects on innovation can be hard to assess, because of the inherent uncertainty associated with R&D, because of the difficulty of evaluating an organization’s innovation capabilities, and because these effects are more distant in the future. However, they can be very important, due to the critical role of innovation in generating long-term consumer benefits.

The revised Guidelines also add language in Section 10, “Efficiencies,” to clarify that the Agencies recognize and account for the possibility that a merger may generate innovation efficiencies.

When evaluating the effects of a merger on innovation, the Agencies consider the ability of the merged firm to conduct research or development more effectively. Such efficiencies may spur innovation but not affect short-term pricing. The Agencies also consider the ability of the merged firm to appropriate a greater fraction of the benefits resulting from its innovations.\textsuperscript{114}

Section 6.4 also addresses product variety. The analysis of product variety is very similar to the treatment of shorter-term innovation effects just described. The focus here, however, is on the withdrawal of existing products rather than the cancellation or delay of new products. A very similar approach, focusing on diversion and cannibalization of profits, is applied: “An anticompetitive incentive to eliminate a product as a result of the merger is greater and more likely, the larger is the share of profits from that product coming at the expense of profits from products sold by the merger partner.”\textsuperscript{115} This passage explains how one can distinguish between reductions of product variety that are “largely due to a loss of competitive incentives attributable to the merger”\textsuperscript{116} and those that are not anticompetitive. Anticompetitive reductions in product variety may well be accompanied by a price increase on the remaining product.

IV. MARKET DEFINITION AND THE HYPOTHETICAL MONOPOLIST TEST

Market definition plays two roles in the Guidelines. First, market definition specifies the line of commerce and section of the country in

\textsuperscript{114} Id. § 10.
\textsuperscript{115} Id. § 6.4.
\textsuperscript{116} Id.
which the competitive concern arises. Second, market definition allows the Agencies to identify market participants and measure market shares, which can be informative regarding the merger’s likely competitive effects. The Guidelines retain the basic hypothetical monopolist test used since 1982 to define relevant markets.

The 2010 Guidelines explain more fully (a) how the exercise of defining markets and measuring concentration relates to the ultimate question of whether the merger may substantially lessen competition; (b) why using market concentration measures based on broader groups of substitutes than required by the HMT can be misleading; (c) how the Agencies evaluate and perform critical loss analysis; and (d) how the Agencies define price discrimination markets, including geographic markets based on the locations of customers.

A. The Role of the Hypothetical Monopolist Test

The HMT provides a well-defined and coherent method for delineating the relevant market. The test can be employed even in situations where there is no clear break in the chain of substitutes and where customers differ greatly in their willingness to substitute more distant products in response to a price increase. As Section 4.1.1 of the Guidelines states: “The Agencies use the hypothetical monopolist test to identify a set of products that are reasonably interchangeable with a product sold by one of the merging firms.” The HMT plays a very specific role in the Guidelines, Section 4:

However, a group of products is too narrow to constitute a relevant market if competition from products outside that group is so ample that even the complete elimination of competition within the group would not significantly harm either direct customers or downstream consumers. The hypothetical monopolist test (see Section 4.1.1) is designed to ensure that candidate markets are not overly narrow in this respect.

A group of products can form a relevant market under the HMT even if there is significant substitution between that group of products and other products: “As a result, properly defined antitrust markets often exclude some substitutes to which some customers might turn in the face of a price increase even if such substitutes provide alternatives for those customers.”

117 Id. § 4.1.1.
118 Id. § 4.
119 Id.
merger test without including the full range of substitutes from which customers choose.”

These statements follow from the economic logic of the HMT. They do not reflect any change in how the Agencies define relevant markets. For example, the 2006 Commentary states:

Defining markets under the Guidelines’ method does not necessarily result in markets that include the full range of functional substitutes from which customers choose. . . . The Agencies frequently conclude that a relatively narrow range of products or geographic space within a larger group describes the competitive arena within which significant anticompetitive effects are possible. . . .

The description of an “antitrust market” sometimes requires several qualifying words and as such does not reflect common business usage of the word “market.” Antitrust markets are entirely appropriate to the extent that they realistically describe the range of products and geographic areas within which a hypothetical monopolist would raise price significantly and in which a merger’s likely competitive effects would be felt. . . .

Even when no readily apparent gap exists in the chain of substitutes, drawing a market boundary within the chain may be entirely appropriate when a hypothetical monopolist over just a segment of the chain of substitutes would raise prices significantly.

Some comments have suggested that the Guidelines now point to narrower markets than did the 1992 Guidelines. This is incorrect: the basic HMT remains unchanged. If anything, the opposite is true, since the “smallest market principle” has been relaxed, as I explain next.

B. IMPLEMENTING THE HYPOTHETICAL MONOPOLIST TEST

The basic HMT dates back to the 1982 Guidelines. The implementation of the test has been slightly modified over the intervening twenty-eight years, during which time we have learned a great deal about the operation of the test, both in theory and in practice. That process continues in 2010.

As noted above, the Guidelines were updated in 1992 to better handle markets with differentiated products. As part of that updating, the 1992 Guidelines explicitly directed attention to the profit-maximizing price increases on the various products controlled by the hypothetical monopolist.
ologist, recognizing that these price increases typically will not be uniform.\textsuperscript{124}

The 1992 Guidelines implement the HMT using a specific, iterative algorithm.\textsuperscript{125} Products are added to the candidate market in the order of “next best substitutes” and the exercise is halted once the test is satisfied. “The Agency generally will consider the relevant product market to be the smallest group of products that satisfies this test.”\textsuperscript{126} The algorithm has much to commend it, but it suffers from a theoretical problem and a practical problem. The theoretical problem is that the “smallest market principle,” can fail to detect a merger as horizontal in some cases where the merging firms sell substitute products and their merger would likely lead to a substantial lessening of competition.\textsuperscript{127} The practical problem is that one may not be able to identify the “next best substitute” at each stage of the algorithm, yet the outcome of the iterative algorithm can be sensitive to this determination.\textsuperscript{128} As a result, while the iterative test in the 1992 Guidelines provides a very useful conceptual framework, in practice the Agencies often are unable to implement the test as stated.

Recognizing these difficulties, the revised Guidelines retain the HMT but take a more flexible approach to its implementation. The iterative procedure no longer appears. The smallest market principle is softened, and the scope of its use is explained in Section 4.1.1:

The Agencies may evaluate a merger in any relevant market satisfying the test, guided by the overarching principle that the purpose of defin-

\textsuperscript{124} In markets involving differentiated products, prices typically differ among various products in the market, and the price effects of a merger need not be uniform. Accordingly, the 1992 Guidelines state that “the hypothetical monopolist will be assumed to pursue maximum profits in deciding whether to raise the prices of any or all of the additional products under its control.” 1992 Guidelines, supra note 2, § 1.11 (emphasis added). They then state that a group of products satisfies the test if a hypothetical monopolist over that group of products would profitably impose at least a small but significant and nontransitory increase in price (SSNIP) “including the price of a product of one of the merging firms.” Id. These points are discussed at greater length by two of the principal authors of the 1992 Guidelines. See Janusz A. Ordover & Robert D. Willig, Economics and the 1992 Merger Guidelines: A Brief Survey, 8 Rev. Indus. Org. 139, 140 (1993).

\textsuperscript{125} See 1992 Guidelines, supra note 2, § 1.11.

\textsuperscript{126} Id.

\textsuperscript{127} See Carl Shapiro, Deputy Ass’t Att’y Gen., Antitrust Div., U.S. Dep’t of Justice, Updating the Merger Guidelines: Issues for the Upcoming Workshops, Speech Before the Fall Forum, ABA Antitrust Section (Nov. 12, 2009), available at http://www.justice.gov/atr/public/speeches/251858.pdf; Salop & Moresi, supra note 90. This problem was recognized back in 1992 and can be dealt with in a somewhat ad hoc manner by increasing the SSNIP size.

\textsuperscript{128} Furthermore, if one is able to determine the profit-maximizing prices for a series of hypothetical monopolists, one likely can also determine the profit-maximizing prices for the merged firm (taking as given the products offered by non-merging firms and their prices), which provides a more direct way of evaluating unilateral price effects.
ing the market and measuring market shares is to illuminate the evaluation of competitive effects. Because the relative competitive significance of more distant substitutes is apt to be overstated by their share of sales, when the Agencies rely on market shares and concentration, they usually do so in the smallest relevant market satisfying the hypothetical monopolist test.\footnote{2010 Guidelines, \textit{supra} note 1, § 4.1.1.}

\section*{C. The Role of Price/Cost Margins in the Hypothetical Monopolist Test}

The 2010 Guidelines are more explicit than their predecessors about the role played by price/cost margins in the HMT. Section 4.1.3, "Implementing the Hypothetical Monopolist Test," begins:

The hypothetical monopolist’s incentive to raise prices depends both on the extent to which customers would likely substitute away from the products in the candidate market in response to such a price increase and on the profit margins earned on those products. The profit margin on incremental units is the difference between price and incremental cost on those units.\footnote{Id. § 4.1.3.}

The revised Guidelines have not changed the role of profit margins in the HMT. The central role played by these margins follows from the economic logic inherent in the test. The 2010 Guidelines \textit{explain} the role of profit margins in a way that reflects Agency experience and practice since 1992 along with advances in economic learning during that time.

The HMT asks a very specific economic question: would a profit-maximizing monopolist controlling a group of products raise the price of at least one of those products by at least a SSNIP? \textit{As noted above, the answer to this question depends entirely on (a) how the demand for these products varies as their prices rise above pre-merger levels; and (b) pre-merger price/cost margins.} Example 5 in the Guidelines illustrates how the test works using this information.

In principle, one can perform the HMT by estimating the demand for the products in the candidate market, measuring pre-merger margins, and then computing the profit-maximizing prices.\footnote{See supra note 82 for further explanation. See also Werden, \textit{Demand Elasticities}, \textit{supra} note 44, at 387–91 (providing the underlying calculations in the case of a candidate market containing a single homogeneous product).} DOJ economists and the economists consulting for the merging parties routinely devote
considerable effort to estimating demand, using whatever reliable and relevant data are available. However, we often lack sufficient data to reliably and robustly estimate the demand system, making it necessary to follow approaches that are less stringent in terms of their data or modeling requirements. Furthermore, since we are often trying, at least initially, to screen mergers based on market concentration, it is highly desirable to have relatively simple methods of defining the relevant market that do not require the econometric estimation of an entire demand system. Fortunately, we have learned a great deal over the past twenty years about how to exploit the information contained in pre-merger prices, costs, and diversion ratios to perform the HMT without full estimation of the demand system.133

By focusing on how the pricing incentives facing the hypothetical monopolist differ from the pricing incentives of firms independently owning and controlling the relevant products prior to the merger, the HMT can be grounded in reality. Focusing on the change in incentives is a major and very sensible and practical simplification. The Clayton Act standard—whether the merger may substantially lessen competition—is explicitly focused on the change resulting from the merger. The unifying theme of the Guidelines since 1982 has also been about the change: whether the merger will enhance market power. And the HMT itself asks about whether the hypothetical monopolist will raise prices by at least a SSNIP, which again looks at a change from pre-merger conditions.

The hypothetical monopolist’s pricing incentives differ from those of the pre-merger firms because the hypothetical monopolist owns a larger group of substitute products. The hypothetical monopolist does not lose sales when the price of one product is elevated and customers shift away from that product to other products it owns. Therefore, in considering how the hypothetical monopolist’s incentive to raise the price of one product differs from the pre-merger incentives of the firm controlling that product, a key question is what percentage of the unit sales lost, when that product’s price rises, are recaptured by other products controlled by the hypothetical monopolist. This percentage is defined in Section 4.1.3 of the Guidelines as the recapture percentage, “with a higher separate measurement of market shares superfluous for the purpose of predicting post-merger unilateral price increases.

133 For an entrée to that literature, see Werden, Demand Elasticities, supra note 44; Epstein & Rubinfeld, supra 56; Farrell & Shapiro, Recapture, Pass-Through, and Market Definition, supra note 85; Joseph Farrell & Carl Shapiro, Improving Critical Loss Analysis, Antitrust Source, Feb. 2008, http://www.abanet.org/antitrust/at-source/08/02/Feb08-Farrell-Shapiro.pdf; Davis & Garcés, supra note 57. Also see the references cited in these articles.
recapture percentage making a price increase more profitable for the hypothetical monopolist.” In some cases, the Agencies can glean information about the recapture percentage even if they lack sufficient data to estimate the entire demand system. For example, if the price of one product was raised in the past (or if supplies of that product were disrupted or limited), one may be able to track how customers of that product shifted to other products. The recapture percentage is closely related to the cross-elasticity of demand that has been central to market definition for decades.134

The hypothetical monopolist’s incentive to raise the price on any one product under its control depends on the recapture percentage associated with that product and on the margins it receives on the sales recaptured by the other products it owns.135 Kevin Murphy and Bob Topel put it this way: “A larger fraction of sales diverted to other firms in the market or a larger profit margin on these sales will make the incentive to increase price greater for the hypothetical monopolist.”136 Applying this fundamental economic logic, the Guidelines state: “The higher the pre-merger margin, the smaller the recapture percentage necessary for the candidate market to satisfy the hypothetical monopolist test.”137 This is the same basic economic logic we saw above in the evaluation of unilateral price effects.

With linear demand, if each firm selling one of a symmetric group of differentiated products is setting its pre-merger price independently, that group of products forms a relevant market if the recapture percentage for any one product is at least as large as \( 2S/(M + 2S) \), where \( S \) is the size of the SSNIP and \( M \) is the pre-merger margin.138 In this special case, Appendix A shows that a symmetric pair of products satisfies the HMT if GUPPI is at least 10 percent. This highlights the tight connection between unilateral effects and market definition.

D. CRITICAL LOSS ANALYSIS

Merging parties sometimes conduct a “critical loss analysis,” typically to support their claim that a certain candidate market in which they

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135 The relevant cost concept here is the average incremental cost on these recaptured sales.
136 Murphy & Topel, supra note 99, at 8–9.
137 2010 Guidelines, supra note 1, § 4.1.3.
138 See Michael Katz & Carl Shapiro, Critical Loss: Let’s Tell the Whole Story, ANTITRUST, Spring 2003, at 49. In this case, profit maximization implies a uniform price increase for all of the products, and that uniform price increase exceeds the profit-maximizing price increase on a single product alone.
have large shares is too narrow to satisfy the HMT. Critical loss analysis relies heavily on price/cost margins. The Guidelines now explain how the Agencies evaluate and properly conduct critical loss analysis. Since critical loss analyses have long been presented to the Agencies by merging parties, this explanation is overdue.

Most critical loss analyses presented to the Agencies use the “breakeven” approach.139 The Guidelines note that “this ‘breakeven’ analysis differs from the profit-maximizing analysis called for by the hypothetical monopolist test” since 1984.140 Breakeven analysis compares the “critical loss” with the “predicted loss.” The Agencies and others have been aware for some time of a fundamental flaw appearing in a number of breakeven critical loss analyses they receive. The flaw arises when the predicted loss is not reconciled with the pre-merger margins. Michael Katz, writing when he was Economics Deputy at the DOJ in 2002, described this flaw in some detail in his discussion of the Sungard case.141 FTC economists were equally aware of the flaw; additional cases are described by Daniel O’Brien and Abraham Wickelgren.142 The UK Competition Commission is also aware of this flaw:

The “fallacy” in this analysis is to treat the elasticity and the margin as if they were independent from each other. In fact, according to the benchmark model, margins tell us about the own-elasticity before the price increase. If margins are high, it implies a low price elasticity and that in turn suggests perhaps even strongly there will be low actual losses due to a price increase.143

The same flaw appeared more recently in the Whole Foods case.144 The revised Guidelines alert practitioners to this flaw and explain how the

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139 This approach was pioneered by Barry Harris and Joseph Simons, who introduced the term “critical loss.” See Barry C. Harris & Joseph J. Simons, Focusing Market Definition: How Much Substitution Is Necessary?, 12 Res. L. & Econ. 207 (1989).
140 2010 Guidelines, supra note 1, 4.1.3.
142 Daniel P. O’Brien & Abraham L. Wickelgren, A Critical Analysis of Critical Loss Analysis, 71 Antitrust L.J. 161 (2003). Both authors were economists at the FTC when they wrote this article.
143 Davis & García, supra note 57, at 212. Davis is currently a Deputy Chairman of the UK Competition Commission.
144 See FTC v. Whole Foods Mkt. Inc., 548 F. 3d 1028, 1048 (D.C. Cir. 2008) (discussing Kevin M. Murphy’s testimony regarding the flaw in critical loss). Murphy and Topel write:

Our point in this comment is not to criticize the application of critical loss analysis to market definition in [the Whole Foods merger] case. Rather, we illustrate why the [critical loss] analysis used by Whole Foods’ economist is not useful as a
Agencies evaluate breakeven critical loss analysis: “Higher pre-merger margins thus indicate a smaller predicted loss as well as a smaller critical loss.”

See Appendix A for further details.

V. TARGETED CUSTOMERS AND PRICE DISCRIMINATION

The revised Guidelines add a separate section on targeted customers and price discrimination. This section sets forth the two basic conditions necessary for price discrimination to be feasible: differential pricing and limited arbitrage. The basic principles explained here have been well understood by economists for roughly one hundred years. They can be found in the Guidelines going back to 1982 and are not controversial.

Price discrimination is frequently an important factor in DOJ merger investigations. The majority of our mergers involve intermediate goods and services. In these markets, prices typically are negotiated and price discrimination is common. For example, manufacturers may negotiate lower prices with larger customers than with smaller customers, and these price differences may constitute price discrimination, i.e., they may not merely reflect lower costs of supplying the larger customers. In other settings, established customers with high costs of switching away from their incumbent supplier may pay higher prices than new customers. In yet other settings, prices vary across customers based on their locations in a manner not merely reflecting transportation costs. This is relevant for geographic markets based on customer location.

This new section was placed relatively early in the Guidelines because the basic principles of price discrimination articulated here are used throughout the Guidelines. They are relevant to market definition. For that purpose, we usually are asking whether the hypothetical monopolist can engage in price discrimination. They are also relevant to competitive effects. When considering unilateral effects, we often ask whether the merged firm can engage in price discrimination. In some cases, we ask whether the merged firm can raise prices to certain customers by ending discrimination that had been in their favor. When considering

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145 2010 Guidelines, supra note 1, § 4.1.3.
146 In keeping with the general style of the Guidelines, the discussion in Section 3 addresses price discrimination, as distinct from discrimination on other dimensions, such as quality or service. This is purely for simplicity of exposition. The same basic principles described in this section also apply to non-price forms of discrimination.
147 See 2010 Guidelines, supra note 1, § 4.2.2.
coordinated effects, we may ask whether a group of coordinating firms could engage in price discrimination.

In fact, DOJ investigations often begin by asking whether there are particular types of customers who are most likely to be harmed by the merger. We often find that some types of customers are more vulnerable than others to adverse competitive effects. We look for pre-existing price discrimination and we consider the possibility of post-merger price discrimination.

The Guidelines address the danger that mergers may harm some customers more than others, or some customers but not others, usually by making a discriminatory price increase profitable. But this observation should not be taken to imply any hostility to price discrimination as a stand-alone form of business conduct.148 For many years, economists have studied the effects of price discrimination, usually by comparing price discrimination with uniform pricing. These studies are directly relevant to the evaluation of regulations that limit or prohibit price discrimination.149 But the comparison of uniform pricing and price discrimination is not directly relevant for the analysis of horizontal mergers, and the Guidelines do not undertake any such comparison. Nor do the Guidelines address the issue of whether or when price discrimination by a firm indicates that the firm has significant market power under the antitrust laws. The Guidelines are focused on whether the merger is likely to enhance market power. Price discrimination is highly relevant to this question if the merger may enhance market power over some customers but not others.

VI. POWERFUL BUYERS

The revised Guidelines add a discussion of “Powerful Buyers” in Section 8. In this respect, they follow the lead of the European Commission’s 2004 Horizontal Merger Guidelines, which include a discussion of “Countervailing Buyer Power.”150

Many DOJ merger investigations involve intermediate goods markets, where the customers of the merging firms are themselves sizeable enterprises. Merging parties often argue that their customers are large and powerful and will not be vulnerable to adverse competitive effects. This

148 Similarly, the Guidelines focus on whether a merger will lead to higher prices, but of course this does not mean that high prices alone constitute an antitrust violation.


150 EU Horizontal Merger Guidelines, supra note 104, ¶¶ 64–67.
section explains how the Agencies evaluate “power buyer” arguments and how merger analysis is influenced by the presence of large or powerful buyers.

Three basic economic themes underlie this section. First, whatever leverage buyers have in negotiations must ultimately rest on the alternatives available to them. In some cases, larger buyers are better placed than small buyers to vertically integrate upstream or sponsor entry, or to shift a greater portion of their business to price cutters. Options such as these can give larger buyers additional bargaining leverage. In contrast, mere size alone, without options, does not normally create bargaining leverage, although it can imply large gains from trade.

Second, the Agencies are interested in the impact of the merger on all buyers, not just powerful buyers. The Guidelines state: “Furthermore, even if some powerful buyers could protect themselves, the Agencies also consider whether market power can be exercised against other buyers.” The 2006 Commentary sounded a similar message:

Large buyers rarely can negate the likelihood that an otherwise anticompetitive merger between sellers would harm at least some buyers. Most markets with large buyers also have other buyers against which market power can be exercised even if some large buyers could protect themselves. Moreover, even very large buyers may be unable to thwart the exercise of market power.

In some cases, the actions of powerful buyers can protect more vulnerable customers, e.g., when the lumpy sales of the large buyers disrupt coordination and engender price wars. However, this is not always the case, particularly when the concerns involve unilateral effects. If powerful buyers are protected and other buyers are not, there may be a price discrimination market in which those other buyers are the targeted customers.

Third, the Agencies focus on how the merger will change bargaining leverage. “The Agencies examine the choices available to powerful buyers and how those choices likely would change due to the merger. Normally, a merger that eliminates a supplier whose presence contributed significantly to a buyer’s negotiating leverage will harm that buyer.”

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151 However, in some situations, larger buyers have more demanding requirements than smaller buyers, giving them fewer options.
152 2010 Guidelines, supra note 1, § 8.
153 2006 Commentary, supra note 4, at 17–18.
154 2010 Guidelines, supra note 1, § 8.
These principles can be applied to situations in which a large buyer purchases other products from the merging firms in addition to the products over which they compete. Merging parties sometimes assert that the merged firm would be foolish to try to raise price to such a powerful buyer, because that buyer would retaliate by shifting its purchases of these other products away from the merged firm. While buyers of this type do have an extra tool at their disposal, and may indeed be able as a consequence to negotiate lower prices than other buyers, such buyers will normally still be harmed if the merger eliminates a supplier whose presence contributed significantly to their negotiating leverage.

VII. CONCLUSION

The 2010 Guidelines provide updated and more accurate guidance regarding merger enforcement at the DOJ and the FTC than did the 1992 Guidelines, which they replace.
APPENDIX A

UNILATERAL PRICE EFFECTS:
THE ROLE OF DIVERSION RATIOS AND MARGINS

The Guidelines identify diversion ratios, margins, and the value of diverted sales as objects that the Agencies seek to measure to diagnose unilateral price effects in markets with differentiated products. The Guidelines also, for the first time, list merger simulation as one of the tools used by the Agencies to “quantify the unilateral price effect resulting from a merger.”

Merger simulation, in its full-blown form, involves estimating the demand system for a set of differentiated products, backing out or directly measuring marginal costs, computing the post-merger equilibrium, and then comparing pre-merger and post-merger prices. In principle, this is the “gold standard,” since it involves predicting post-merger price increases based on detailed demand and cost information, under some maintained assumption about oligopolistic behavior, usually independent (Bertrand) pricing behavior. However, the data required for full merger simulation are often not available, the predictions of merger simulation models may not be robust, and merger simulation techniques can be opaque to non-specialists. Therefore, less demanding and less sophisticated methods are often needed.

One way to achieve substantial simplification and increased transparency is to focus just on the demand for the products sold by the merging firms, holding fixed the prices of competing products sold by non-merging parties. As noted in the text, doing so will normally generate smaller price effects than the full model; but the simplification is considerable and the price effects coming out of the full model often differ very little from those of the simplified model.

With this major simplification, we rephrase the key question posed in the text: “Taking as given all other products and their prices, how much higher are the merged firm’s profit-maximizing prices for Products 1 and 2 than the pre-merger prices of those products?” If we can answer this question, we can derive a useful diagnostic measure of tendency of the merger to raise the price of these products. Technically, this diagnostic consists of the post-merger price increases for Products 1 and 2, holding other prices constant, and assuming that there is no repositioning or entry and no efficiencies. This diagnostic measure is not a “prediction” of the post-merger price increases. The diagnostic measure provides a relatively simple way of ranking or scoring mergers by their
tendency to raise price. Predicting post-merger price increases requires further analysis.

One good diagnostic measure relies on the fact that one can treat GUPPI as a post-merger opportunity cost for Product 1, and then apply a default pass-through rate to those costs, holding fixed the price of Product 2. Basing the default pass-through rate on linear demand gives a pass-through rate of 50 percent; this figure is within the general range of pass-through rates that are estimated empirically. With a default pass-through rate of 50 percent, the indicated price increase, measured as a fraction of the price of Product 1, is

$$\frac{1}{2} GUPPI_i$$

which equals

$$\frac{1}{2} \frac{D_{12} M_2}{P_2} \frac{P_2}{P_1}$$

With equal prices, this becomes

$$\frac{1}{2} D_{12} M_2.$$  

Using this method, a 10 percent value of GUPPI translates into an indicated price increase of 5 percent.

This approach has been criticized for holding fixed the price of Product 2 when calculating the indicated price increase for Product 1. Instead, one can specify the demand system at prices just above pre-merger levels and calculate the indicated post-merger prices for that demand system. A larger indicated price increase, with a somewhat different ranking, is obtained by simultaneously considering a price increase for Product 2. Yet again, Willig led the way, working with a linear demand system for Products 1 and 2. He writes:

155 More specifically, a diagnostic measure is most useful if it is informative in ranking mergers that are likely to lead to small or moderate price increases. Those are the mergers where such diagnostics can help inform the Agency’s enforcement decision. The ability of the diagnostic to rank mergers likely to lead to large price increases is less important.

156 If we are only concerned about ranking mergers using this measure of the gross upward pricing pressure, the choice of the default pass-through rate does not matter.

157 See Richard Schmalensee, Should New Merger Guidelines Give UPP Market Definition?, GCP ANTITRUST CHRONICLE, Dec. 2009. As Schmalensee points out, accounting for an increase in the price of Product 2 leads to a larger price increase without efficiencies and increases the efficiencies required to prevent the merger from generating net upward pricing pressure.
The merger will elevate the price of good 1 according to two effects. One focuses on the initial price-cost margin of good 2, multiplied by the absolute value of the ratio of the cross-price and own-price derivatives of demand for goods 2 and 1. The second effect adds further price elevation to good 1, depending on the elevation in the price of good 2 and the same ratio of demand derivatives.158

A few years later, I extended Willig’s work by expressing the post-merger price increase in the linear model solely in terms of the pre-merger diversion ratios and margins.159 In the symmetric case, where the two products face equal demand and have equal marginal costs, profits are maximized by raising the prices of the Products 1 and 2 the same amount. The indicated (uniform) price increase in this model is equal to

\[
\frac{D \times M}{2(1-D)}
\]

This ranking puts more weight on the diversion ratio than on the margin.

This entire analysis is very closely related to the market definition exercise. Indeed, the question we have been asking—what are the profit-maximizing prices of Product 1 and 2 given the prices of all other products—is precisely the question posed by the HMT when evaluating these two products as a candidate market. The HMT asks whether this price increase is at least as large as the SSNIP, \( S \). With symmetry and linear demand, profits are maximized by raising the prices of both products equally, so the results of the HMT are the same whether one is considering the profit-maximizing price increase on one product (with the price on the other product also adjusting to maximize profits) or the profit-maximizing (uniform) price increase on both products. With linear demand, the profit-maximizing post-merger (uniform) price increase is at least a SSNIP if

\[
\frac{D \times M}{2(1-D)} \geq S.
\]

Rearranging, this becomes

[158 Willig, supra note 46, at 300 n.43.
159 See Shapiro, Mergers with Differentiated Products (Antitrust article), supra note 45, at 27. For a full set of calculations, allowing for asymmetry and for efficiencies, see Carl Shapiro, Unilateral Effects Calculations (unpublished manuscript), available at http://faculty.haas.berkeley.edu/shapiro/unilateral.pdf. See also Jerry Hausman, Serge Moresi & Mark Rainey, Unilateral Effects with General Linear Demand, ECON. LETTERS (forthcoming) (pre-publication version available at http://crai.com/uploadedFiles/Publications/UnilateralEffects-of-Mergers-with-General-Linear-Demand-Hausman-Moresi-Rainey.pdf).]
This is the same formula reported in the text for the minimum group recapture ratio necessary for a group of products to form a relevant market with linear demand (with the diversion ratio here replacing the group recapture ratio in the text, since here the candidate market contains just two products).

With linear demand, the HMT is directly related to GUPPI. We just noted that the two products form a relevant market if \( D \times M \geq 2(1 - D)S \). In the symmetric case, \( \text{GUPPI} = D \times M \), so this becomes \( \text{GUPPI} \geq 2(1 - D)S \). A sufficient condition for the two products to form a relevant market is \( \text{GUPPI} \geq 2S \). Using the standard 5 percent SSNIP, the two products form a relevant market if GUPPI is at least 10 percent.\(^{160}\) The HMT is satisfied with a somewhat smaller GUPPI; the precise level required is \( 0.1 \times (1 - D) \). If the diversion ratio is 25 percent, a GUPPI of 7.5 percent is sufficient to satisfy the HMT.

One can easily integrate efficiencies into this type of analysis. Suppose the merger causes the marginal cost of Products 1 and 2 to fall from \( C \) to \( C(1 - E) \). Then the indicated price increase in the linear symmetric model is equal to\(^{161}\)

\[
\frac{D \times M}{2(1-D)} - \frac{E(1-M)}{2}.
\]

Prices rise if, and only if, this expression is positive. The minimum efficiencies necessary to prevent prices from rising, measured in percentage of pre-merger marginal cost, are given by

\[
E = \frac{D \times M}{(1-D)(1-M)}.
\]

In a very important article, Werden showed that this condition applies \textit{regardless} of the shape of the demand system.\(^{162}\) Equally generally, he showed that the minimum efficiencies necessary to prevent prices from rising, measured as a percentage of the price, are given by

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\(^{160}\) Similar but more complex calculations can be done in the asymmetric case. These calculations require information on the relative price of the two products, the two diversion ratios, and the two margins.

\(^{161}\) See Schmalensee, supra note 157; Shapiro, \textit{Mergers with Differentiated Products (Antitrust article)}, supra note 45. For the asymmetric case, see Shapiro, \textit{Unilateral Effects Calculations}, supra note 159.

\(^{162}\) See Werden, \textit{A Robust Test}, supra note 96. Werden also worked out the asymmetric case.
\[
\frac{DM}{1-D}.
\]

This formula may be more applicable if the efficiencies involve improvements in product quality or service, which may be more closely related to the value (price) of the product than its marginal cost. With linear demand, the indicated price increase is just half as large as this measure.
APPENDIX B
DIFFERENTIATED OLIGOPOLY: TOXONOMICS,
A HYPOTHETICAL

In the land of Tox, all households and businesses unavoidably and steadily generate a highly toxic substance, Toxon. Toxon must be treated at dedicated facilities, which require highly specialized and expensive equipment. A long and expensive permitting process is needed to establish a Toxon treatment facility. Transporting Toxon is hazardous and very costly.

Tox has a free-enterprise economy. Private, for-profit firms compete to handle the critical job of Toxon treatment. These firms build Toxon treatment sites where they expect them to be profitable, and close them when and if they become unprofitable to operate. These firms set their Toxon treatment fees independently. The marginal cost of disposing of one unit of Toxon is $60. Toxon treatment facilities are differentiated based on their locations and based on other attributes, such as service quality and reputation.

Each Toxon treatment site faces competition from neighboring sites, but also has some control over its own price. Any given site will lose some customers, mostly to adjacent sites, if it raises its price slightly. But a site that slightly raises its prices is unlikely to lose its nearest customers, who have the farthest to travel to other sites. Suppose that each site maximizes its profits by setting a price of $100 per unit of Toxon. This is a markup of $40 over the marginal cost. Measured as percentage of the price, the markup is 40 percent. These markups contribute to covering the substantial fixed costs of establishing a site and to profits. Without the prospect of earning such markups, no firm would ever build a site.

Before we consider a proposed merger between two adjacent Toxon treatment sites, it is instructive to make some observations about the Toxon treatment industry.

First, this type of market structure, which economists call a differentiated oligopoly, has been well understood by economists going back at least to the 1920s and 1930s.163 In a differentiated oligopoly, each supplier faces competition yet has some ability to control price.

163 There is a huge economic literature on differentiated oligopolies. The classic reference for a one-dimensional version of spatial competition is Hotelling, supra note 99. See also Edward H. Chamberlin, The Theory of Monopolistic Competition (1933); Joan Robinson, The Economics of Imperfect Competition (1933). If there are no barriers to entry, this market structure is called “monopolistic competition.”
Second, the Toxon treatment prices obey the textbook rule relating margins to the elasticity of demand. This relationship is sometimes presented in introductory economics classes as the rule that marginal revenue equals marginal cost, \( MR = MC \). Equivalently, it can be presented as the fundamental markup rule, which states that the firm’s margin is inversely related to the firm’s own elasticity of demand,

\[
\frac{P - C}{P} = \frac{1}{E},
\]

where \( P \) is price, \( C \) is marginal cost, and \( E \) is the elasticity of demand facing the firm. This latter form of the rule is sometimes referred to as the Lerner Equation.\(^{164}\) So long as this basic rule applies, a high margin is evidence that a firm believes that its customers are not highly sensitive to the price it sets.\(^{165}\) As Kevin Murphy and Robert Topel state: “A well-known result of basic economics is that a profit-maximizing seller sets price so that the actual percentage reduction in quantity sold from a small percentage increase in price is equal to \( 1/m \).”\(^{166}\)

A variant of this last statement appears in the revised Guidelines in Section 2.2.1. While the statement is uncontroversial among industrial organization economists, it sparked a number of comments. For example, the ABA Antitrust Section questioned this basic rule relating margins to the elasticity of demand, calling it “unjustified.”\(^{167}\) However, the rule follows directly from the standard working assumption that firms set prices to maximize profits. Of course, like any simple rule in economics, complications arise in practice so it must be used with care. A distinguished group of economists put it this way:

In conclusion, the inverse relationship between the price/cost margin and the firm’s own-price elasticity follows from the fundamental working assumption of profit-maximization, has a long history in economics and remains relevant for careful and reliable merger analysis, along


\(^{165}\) If the firm sets its price independently of its rivals, as in the Toxon example, this lack of sensitivity typically reflects either that the firm’s product is significantly differentiated or that its rivals face increasing marginal cost (capacity constraints). Alternatively, high margins can result from coordinated interaction. “Coordinated interaction includes conduct not otherwise condemned by the antitrust laws.” 2010 Guidelines, supra note 1, § 7.

\(^{166}\) Murphy & Topel, supra note 99, at 4.

\(^{167}\) ABA Section of Antitrust Law, supra note 76, at 17. The comment correctly observes that the long-run competitive price can greatly exceed short-run marginal cost. The comment does not appear to appreciate that this observation is perfectly consistent with the textbook \( M = 1/E \) rule. That is the essence of the work on monopolistic competition going back to the 1930s. See Chamberlin, supra note 163; Robinson, supra note 163.
with econometric estimates and other facts learned during a full merger analysis.\textsuperscript{168}

Third, nothing in this description of the Toxon treatment industry necessarily requires that any of the treatment sites earn more than a competitive rate of return or possess substantial market power as that term is used in antitrust law. To the contrary: if permits are freely available and there are no other barriers to entry, in a long-run equilibrium each facility will earn no more than a normal, risk-adjusted rate of return on the investment required to establish a treatment site. In such a long-run equilibrium, there is nothing inherently worrisome about the resulting margins for Toxon treatment. Over the long run they are necessary to induce firms to build treatment sites. In the long run with freely available permits, the density of treatment sites balances two forces. The high fixed costs of establishing a treatment site push for relatively few sites, spaced far apart. But the very high costs of transporting Toxon push for a large number of sites, spaced close together. If there are no entry barriers, given enough time for new sites to be established where they are profitable and closed where they are not, some balance between these two forces can be expected.

Some readers of the proposed Guidelines mistakenly read them to indicate that the Agencies regard high margins, standing alone, as worrisome. We do not. High margins are not in themselves of antitrust concern. A footnote was added to put such concerns to rest:

High margins commonly arise for products that are significantly differentiated. Products involving substantial fixed costs typically will be developed only if suppliers expect there to be enough differentiation to support margins sufficient to cover those fixed costs. High margins can be consistent with incumbent firms earning competitive returns.\textsuperscript{169}

As emphasized in the text, unilateral price effects require a combination of diversion ratios and margins. Margins do not operate alone to generate unilateral price effects. If there is little or no diversion between products sold by the merging firms, the merger cannot cause significant unilateral price effects, regardless of the margins on those products.

Fourth, it is instructive to consider how the Toxon treatment industry would be jolted if the cost of transporting Toxon were suddenly re-


\textsuperscript{169} 2010 Guidelines, supra note 1, § 2.2.1 n.3.
duced. Suppose a new technology is invented that sharply reduces these costs by enabling each household and business to place its Toxon in a secure container, a ToxBox, which can safely and cheaply be transported to a treatment site. For simplicity, suppose also that the existing treatment sites are able to treat additional Toxon at the marginal cost of $60 per unit.

The invention of the ToxBox is most unwelcome to owners of Toxon treatment sites. The ToxBox greatly diminishes their chief source of differentiation—location. Each site suddenly faces a more elastic demand, since customers are more willing to travel to a neighboring site rather than pay a premium. The predictable result will be intensified pricing competition among Toxon treatment sites. This will cause prices, and thus margins, to fall.\textsuperscript{170}

Notice the relationship between margins and transportation costs: the invention of the ToxBox reduced transportation costs, and thus raised the elasticity of demand facing each treatment site, leading those sites to reduce their prices and thus their margins. As a general principle, higher margins reflect greater differentiation among the various products. Businesses know this well: they are forever looking for ways to differentiate their products so they are not forced to compete on price alone. Such non-price competition also can generate enormous consumer benefits.

We are now ready to consider a proposed merger of two Toxon treatment sites. We focus on unilateral price effects. The 1992 Guidelines directed our attention to the diversion ratios between the two merging sites. The 2010 Guidelines do the same, but they also direct our attention to the “value of diverted sales,” which effectively (see above) is the multiplicative product of the diversion ratio and the margin. A merger between Site A and Site B creates incentives to raise the price at Site A that are proportional to the number of sales diverted to Site B multiplied by the margin earned on sales at Site B.

If the merging Toxon treatment sites are not adjacent, there is little diversion between them. With a very low diversion ratio, the value of diverted sales is very low as well, regardless of the size of the margin. So, the merger of non-adjacent Toxon sites does not create any significant

\textsuperscript{170} In the short run, the returns earned by owners of Toxon treatment sites will fall. In the long run, with lower margins, each site must process more Toxon to cover its fixed costs. Eventually, some treatment sites will exit if these lower margins are not sufficient to cover their recurrent fixed costs. The invention of the ToxBox, by reducing the Toxon transportation costs, makes it efficient to space Toxon sites farther apart to save on their fixed costs.
unilateral incentive to raise the Toxon treatment price, regardless of the margins.

If the merger involves two adjacent Toxon treatment sites, we measure their proximity using the diversion ratio between the two sites. Nothing new there. Diversion can be significant between Site A and a number of neighboring sites; competitive concerns can arise for a merger between Site A and any such site, not just between Site A and the nearest competing site. But even a high diversion ratio would not raise serious concerns if transportation costs were very low: any attempt by the merged firm to raise prices at one or both of these two adjacent treatment sites would be defeated as customers easily shift to more distant sites. Concerns arise only if the two treatment sites are significant direct competitors—as captured using the diversion ratio—and if customers cannot easily shift to other more distant sites due to significant transportation costs.

All of this tells us that concerns about the merger between two adjacent Toxon treatment sites are far greater in the world without the ToxBox than in the world with the ToxBox. This should not be a controversial point. Indeed, many readers will recognize that we are straying into the question of the relevant geographic market for the treatment of Toxon. The invention of the ToxBox tends to expand this geographic market.

In evaluating the merger of two adjacent Toxon treatment sites, we certainly are interested in measuring Toxon transportation costs. If we can accurately measure these costs, we can ask directly how many customers would respond to an increase in the price of Toxon treatment imposed unilaterally by the merging firm by taking their Toxon to a more distant site owned by a non-merging firm. If the evidence convincingly shows that enough customers would do this to defeat any significant unilateral price increase, we can be confident that the merger will not lead to significant unilateral price effects.

What can we do if we are unable to measure Toxon transportation costs accurately? We can make some inferences about transportation costs using the price/cost margins for Toxon treatment: as explained above, higher transportation costs go along with relatively inelastic demand for any one treatment site and thus with higher margins. If transportation costs were low, any individual site would find it profitable to lower its price to attract more customers. Margins can thus tell us a lot about transportation costs, either as a consistency check if we can separately measure transportation costs, or as an alternative if we cannot.
The bottom line: concerns about the merger of two adjacent Toxon treatment sites are greater, the larger are the price/cost margins at these sites. This conclusion could also be expressed in terms of geographic market definition. Higher margins are indicative of higher transportation costs, which go along with a narrower geographic market.

Before leaving the land of Tox, it is worth stressing that this entire analysis, which focuses on diversion ratios and margins, is directed at the demand for Toxon treatment. A full merger analysis must also consider the supply side: repositioning, entry, and efficiencies. Since a long and expensive permitting process is required to establish a new Toxon treatment facility, repositioning and entry are, by assumption, very difficult in the Toxon treatment industry. Greater efficiencies are required to prevent prices from rising, the larger is the multiplicative product of the diversion ratio and the margin.

What does all this imply about mergers between suppliers of differentiated products? Transportation costs in the land of Tox are analogous to customer preferences for differentiated products in the real world. Higher transportation costs are analogous to stronger customer preferences among brands. If we have sufficient data to see how customers have responded to shifts in the relative prices of the various products, we may be able to directly estimate demand elasticities and cross-elasticities. However, if we lack such data, or as a consistency check on such estimates, margins can tell us what the firms themselves believe about how demand varies with price. This approach has the great virtue of taking advantage of what the true experts—the firms themselves—believe about demand for their products. Using margins in this way does require assuming that the firms set prices to maximize profits, but that working assumption has long been fundamental to merger analysis.

We can apply this same logic to a merger between two nearby retailers. Diversion might be low because many customers will shift to other stores in response to a price rise at one. Margins might be low, especially if these other stores are nearby. Even if diversion ratios and margins are both high, ease of repositioning and entry might protect customers from harm.
COMPETITIVE IMPACT STATEMENT

The United States, pursuant to Section 2(b) of the Antitrust Procedures and Penalties Act ("APPA" or "Tunney Act"), 15 U.S.C. § 16(b)-(h), files this Competitive Impact Statement relating to the proposed Final Judgment submitted for entry in this civil antitrust proceeding.

I. NATURE AND PURPOSE OF THE PROCEEDING

On December 20, 2004, Defendants entered into an Agreement and Plan of Merger under which Exelon Corporation ("Exelon") would merge with Public Service Enterprise Group Incorporated ("PSEG"). On June 22, 2006, the United States filed a civil antitrust Complaint seeking to enjoin the proposed merger. The Complaint alleges that the merger likely would
lessen competition substantially for wholesale electricity in sections of the United States in violation of Section 7 of the Clayton Act, 15 U.S.C. § 18. This loss of competition would result in increased wholesale electricity prices, raising retail electricity prices for millions of residential, commercial, and industrial customers in parts of the Mid-Atlantic states.

At the same time the Complaint was filed, the United States filed a Hold Separate Stipulation and Order (“Stipulation”) and proposed Final Judgment that are designed to eliminate the anticompetitive effects of the merger. Under the proposed Final Judgment, as explained more fully below, Defendants are required to divest six electric generating plants (collectively the “Divestiture Assets”). The Stipulation and proposed Final Judgment require Defendants to take certain steps to ensure that these assets are preserved and maintained and that competition is maintained during the pendency of the ordered divestiture.

The United States and Defendants have stipulated that the proposed Final Judgment may be entered after compliance with the APPA. Entry of the proposed Final Judgment would terminate this action, except that the Court would retain jurisdiction to construe, modify, or enforce the provisions of the proposed Final Judgment and to punish violations of it. Defendants have also stipulated that they will comply with the terms of the Stipulation and the proposed Final Judgment from the date of the signing of the Stipulation, pending entry of the proposed Final Judgment by the Court and the required divestiture. Should the Court decline to enter the proposed Final Judgment, Defendants have also committed to abide by its requirements and those of the Stipulation until the expiration of the time for appeal.
II. DESCRIPTION OF THE EVENTS GIVING RISE TO THE ALLEGED VIOLATION

A. The Defendants and the Proposed Transaction

Defendant Exelon is a Pennsylvania corporation, with its headquarters in Chicago, Illinois; it owns Exelon Generation Company, LLC, which owns electric generating plants located primarily in the Mid-Atlantic and the Midwest with a total generating capacity of more than 25,000 megawatts (“MW”). Defendant PSEG is a New Jersey corporation, with its headquarters in Newark, New Jersey; it owns PSEG Power LLC, which owns electric generating plants located primarily in New Jersey with a total generating capacity of more than 15,000 MW. By combining the generating plants owned by Exelon and PSEG, the proposed merger would enhance the ability and incentive of the merged firm to reduce output and raise prices for wholesale electricity in two areas of the Mid-Atlantic where Defendants are the largest generators of electricity. Thus, the transaction as originally proposed would lessen competition substantially in violation of Section 7 of the Clayton Act, 15 U.S.C. § 18.

B. Wholesale Electricity in the Mid-Atlantic

Electricity supplied to retail customers is generated at electric generating plants, which consist of one or more generating units. An individual generating unit uses any one of several types of generating technologies (including hydroelectric turbine, steam turbine, combustion turbine, or combined cycle) to transform the energy in fuels or the force of flowing water into electricity. The generating units typically are fueled by uranium, coal, oil, or natural gas.
Generating units vary considerably in their operating costs, which are determined primarily by the cost of fuel and the efficiency of the unit’s technology in transforming the energy in fuel into electricity. “Baseload” units – which typically include nuclear and some coal-fired steam turbine units – have relatively low operating costs. “Peaking” units – which typically include oil- and gas-fired combustion turbine units – have relatively high operating costs. “Mid-merit” units – which typically include combined cycle and some coal-fired steam turbine units – have costs lower than those of peaking units but higher than those of baseload units.

Once electricity is generated at a plant, an extensive set of interconnected high-voltage lines and equipment, known as the transmission grid, transports the electricity to lower voltage distribution lines that relay the power to homes and businesses. Transmission grid operators must closely monitor the grid to prevent too little or too much electricity from flowing over the grid, either of which might damage lines or generating units connected to the grid. To prevent such damage and to prevent widespread blackouts from disrupting electricity service, a grid operator will manage the grid to prevent any more electricity from flowing over a transmission line as that line approaches its operating limit (a “transmission constraint”).

In the Mid-Atlantic, the transmission grid is overseen by PJM Interconnection, LLC (“PJM”), a private, non-profit organization whose members include transmission line owners, generation owners, distribution companies, retail customers, and wholesale and retail electricity suppliers. The transmission grid administered by PJM is the largest in the United
States, providing electricity to approximately 51 million people in an area encompassing all or parts of New Jersey, Pennsylvania, Delaware, Maryland, Virginia, West Virginia, the District of Columbia, North Carolina, Kentucky, Ohio, Indiana, Michigan, Tennessee, and Illinois (the “PJM control area”).

PJM oversees two auctions for the sale and purchase of wholesale electricity: a day-ahead auction that clears the day before electricity is to be generated and delivered, and a real-time auction that clears the day electricity is delivered. In these auctions, generation owners located in the PJM control area submit offers to sell electricity and electricity retailers submit bids to purchase electricity. Buyers submit bids that indicate the amount of electricity they are willing to buy at different prices. Sellers submit offers that indicate the amount of electricity they are willing to sell at different prices. PJM adds up the bids and offers to determine the total demand and supply for electricity. The amount of electricity that actually is generated and delivered is determined by the PJM auctions. Buyers and sellers of wholesale electricity may also enter into contracts with each other or with third parties, outside of the PJM auction process; the prices of these contracts generally reflect expected auction prices.

Subject to the physical and engineering limitations of the transmission grid, PJM seeks to have generating units operated in “merit” order, from lowest to highest offer. In the day-ahead auction, as long as transmission constraints are not expected, PJM takes the least expensive offer first and then continues to accept offers to sell at progressively higher prices until the needs for each hour of the next day are covered. In this way, PJM minimizes the total cost of
generating electricity required for the next day. The clearing price for any given hour essentially is determined by the generating unit with the highest offer price that is needed for that hour, and all sellers for that hour receive that price regardless of their offer price or their units’ costs. In the real-time auction, which accounts for differences between anticipated and actual supply and demand, PJM also accepts sellers’ offers in merit order until there is a sufficient quantity of electricity to meet actual demand, subject to the physical and engineering limitations of the transmission grid.

At times, transmission constraints prevent the generating units with the lowest offers from meeting demand in a particular area within the PJM control area. When that happens, PJM often calls on more expensive units located within the smaller area bounded by the transmission constraints (a “constrained area”), and the clearing price for the buyers in that area adjusts accordingly. Because more expensive units are required to meet demand, the clearing price in a constrained area will be higher than it would be absent the transmission constraints.

**PJM East.** One historically constrained area within the PJM control area includes the densely populated northern New Jersey and Philadelphia areas. This area, referred to in the Complaint as “PJM East,” is defined by the “Eastern Interface,” a set of five major transmission lines that divides New Jersey and the Philadelphia area from the rest of the PJM control area. When the Eastern Interface is constrained, PJM is limited in its ability to meet demand located east of the constraint with electricity from generating units located west of the constraint. PJM often responds to constraints on the Eastern Interface by calling on additional generating units
east of the constraint to run, generally resulting in higher prices in PJM East than otherwise
would exist because the cost of additional generation east of the constraint is higher than the cost
of additional generation west of the constraint.

**PJM Central/East.** A second constrained area in PJM includes PJM East, central
Pennsylvania, and eastern Maryland. This area is defined by two major transmission lines known
as “5004” and “5005” that run from western to central Pennsylvania and divide central
Pennsylvania, eastern Maryland, and PJM East (“PJM Central/East”) from the rest of PJM.
When the 5004 and 5005 transmission lines are constrained, PJM is limited in its ability to
supply demand located east of the constraint with electricity from generating units located west
of the constraint. PJM often responds to constraints on the 5004 and 5005 lines by calling on
additional generating units east of the constraint to run, generally resulting in higher prices in
PJM Central/East than otherwise would exist because the cost of additional generation east of the
constraint is higher than the cost of additional generation west of the constraint.

**C. Product Market**

The Complaint alleges that wholesale electricity, electricity that is generated and sold for
resale, is a relevant antitrust product market. Wholesale electricity demand is a function of retail
electricity demand: electricity retailers, who buy wholesale electricity to serve their customers,
must provide exactly the amount of electricity their customers require. Retail electricity
consumers’ demand, however, is largely insensitive to changes in retail price; thus, an increase in
retail prices due to an increase in wholesale prices will have little effect on the quantity of retail
electricity demanded and little effect on the quantity of wholesale electricity demanded. As a result, a small but significant increase in the wholesale price of electricity would not cause a significant number of retail electricity consumers to substitute other energy sources for electricity or otherwise reduce their consumption of electricity.

D. Geographic Markets

The Complaint alleges that “PJM East” and “PJM Central/East” are relevant antitrust geographic markets defined by transmission lines in the PJM control area: PJM East is defined by the Eastern Interface, and PJM Central/East is defined by the 5004 and 5005 transmission lines. When these lines approach their operating limits, purchasers of electricity have limited ability to purchase electricity generated outside the relevant geographic market to meet their needs. At such times, the amount of electricity that could be purchased outside PJM East or PJM Central/East is insufficient to make it unprofitable for generators located inside those areas to make a small but significant price increase. Thus, PJM East and PJM Central/East are relevant antitrust geographic markets.

E. The Competitive Effects of the Transaction on Wholesale Electricity

The Complaint alleges that Exelon’s proposed merger with PSEG would eliminate competition between them and give the merged firm the incentive and ability profitably to raise wholesale electricity prices, resulting in increased retail prices for millions of residential, commercial, and industrial customers in PJM East and PJM Central/East. In PJM East during 2005, more than $10 billion of wholesale electricity was sold for resale to nearly 6 million retail
customers; in PJM Central/East during 2005, more than $19 billion of wholesale electricity was sold for resale to nearly 9 million retail customers. In PJM East and PJM Central/East, the merged firm would own a substantial share of total generating capacity in highly concentrated markets. More importantly, in both geographic markets the merged firm would own low-cost baseload units that provide incentive to raise prices, mid-merit units that provide incentive and ability to raise prices, and certain peaking units that provide additional ability to raise prices in times of high demand.

**Market shares in PJM East and PJM Central/East.** In PJM East, Exelon currently owns approximately 20 percent of the generating capacity and PSEG currently owns approximately 29 percent of the generating capacity. After the merger, Exelon would own approximately 49 percent of the total generating capacity in PJM East. In PJM Central/East, Exelon currently owns approximately 19 percent of the generating capacity and PSEG currently owns approximately 21 percent of the generating capacity. After the merger, Exelon would own approximately 40 percent of the total generating capacity in PJM Central/East.

**Concentration in PJM East and PJM Central/East.** The U.S. Department of Justice and the Federal Trade Commission’s 1992 Horizontal Merger Guidelines consider markets in which the post-merger Herfindahl-Hirschman Index (“HHI”), a measure of concentration explained in Appendix A of the Complaint, exceeds 1800 points to be highly concentrated. Transactions that increase the HHI by more than 100 points in highly concentrated markets
presumptively raise significant antitrust concerns under the Horizontal Merger Guidelines. Exelon’s merger with PSEG would yield a post-merger HHI in PJM East of approximately 2750 points, representing an increase of more than 1100 points. Exelon’s merger with PSEG would yield a post-merger HHI in PJM Central/East of approximately 2080 points, representing an increase of approximately 790 points. Thus, the proposed merger raises a presumption of significant antitrust concerns in PJM East and PJM Central/East.

**Increased ability and incentive profitably to withhold output and raise prices.** The Complaint alleges that the proposed merger would substantially lessen competition. The combination of PSEG and Exelon’s generating units would increase the merged firm’s ability and incentive to withhold selected output, forcing PJM to turn to more expensive units to meet demand, resulting in higher clearing prices in PJM East and PJM Central/East.

Baseload units, such as nuclear steam and some hydroelectric units, typically generate electricity around the clock during most of the year; certain lower-cost mid-merit units, including some coal-fired steam units, generate electricity for a substantial number of hours during the year. When they are running, such baseload and mid-merit units are positioned to benefit from an increase in wholesale electricity prices. Because they run so frequently, these units provide a relatively significant incentive to withhold output and raise prices.

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Mid-merit units also provide substantial ability to withhold output to increase the market clearing price. Mid-merit units have costs that are close to clearing prices for a substantial number of hours during the year. Because their costs are so close to clearing prices, the opportunity cost of withholding output from these units – the lost profit on the withheld output – is smaller than it would be for low-cost baseload units. This fact is also true of certain peaking units during times of the year when demand is higher.

By giving the merged firm an increased amount of baseload and mid-merit capacity, combined with an increased share of mid-merit and peaking capacity, the merger substantially increases the likelihood that Exelon would find it profitable to withhold output and raise price. With its increased share of mid-merit and peaking capacity, the merged firm would more often be able to reduce output and raise market clearing prices at relatively low cost to it. And with its increased amount of baseload and mid-merit capacity, the merger would make it more likely that the increased revenue on the merged firm’s baseload and mid-merit capacity would outweigh the cost of withholding its higher-cost mid-merit and peaking capacity. Thus the merger facilitates Exelon’s incentive and ability to reduce output and raise market prices.

F. Entry

The Complaint alleges that entry through the construction of new generation or transmission capacity would not be timely, likely, and sufficient to deter or counteract an anticompetitive price increase. Given the necessary environmental, safety, and zoning approvals
required, it would take many years for such new entry to take place. Thus, entry via new
generation or transmission capacity would, at a minimum, not be timely.

III. EXPLANATION OF THE PROPOSED FINAL JUDGMENT

The proposed Final Judgment would preserve the competition that would have been lost
in PJM East and PJM Central/East had Exelon’s merger with PSEG gone forward as proposed.
Within 150 days after consummation of their merger, Defendants must sell all of their rights,
titles, and interests in the Divestiture Assets. The assets and interests will be sold to purchasers
acceptable to the United States in its sole discretion. In addition, the Final Judgment prohibits
the merged company from reacquiring or controlling any of the Divestiture Assets, as well as
limits its ability to acquire, or enter into contracts to control, generating units in PJM East or PJM
Central/East.

A. Divestiture

The Complaint alleges that the merger would significantly enhance the merged firm’s
ability and incentive profitably to reduce output and raise prices in PJM East and PJM
Central/East. The divestiture requirements of the proposed Final Judgment will maintain
competition for wholesale energy in these geographic markets by allowing independent
competitors to acquire the Divestiture Assets. The Divestiture Assets are six generating plants
located in PJM East and PJM Central/East that comprise mid-merit and peaking units:

• Cromby Generating Station, 100 Cromby Rd. at Phoenixville, PA, 19460;
• Eddystone Generating Station, Number 1 Industrial Hwy. at Eddystone, PA, 19022;
• Hudson Generating Station, Duffield & Van Keuren Aves. at Jersey City, NJ, 07306;
• Linden Generating Station, 4001 South Wood Ave. at Linden, NJ, 07036;
• Mercer Generating Station, 2512 Lamberton Rd. at Hamilton, NJ, 08611; and
• Sewaren Generating Station, 751 Cliff Rd. at Sewaren, NJ, 07077.

The Divestiture Assets include all of the merged firm’s coal-fired steam units in PJM East and PJM Central/East (located at the Eddystone, Cromby, Hudson, and Mercer plants); one of the merged firm’s two combined cycle units (located at the Linden plant); and several efficient peaking units (located at the Eddystone, Cromby, Linden, Hudson, and Sewaren plants).

**Effect of divestiture on market shares and concentration.** Divestiture of these plants will reduce market shares and concentration substantially relative to what they would have been absent divestiture. Absent divestiture, the merged firm’s share of capacity would be approximately 49 percent in PJM East and 40 percent in PJM Central/East. With divestiture, the merged firm’s share of capacity will be approximately 32 percent in PJM East and 29 percent in PJM Central/East.

The pre-merger HHI concentration levels for PJM East and Central East are approximately 1590 points and 1290 points, respectively. Absent divestiture, the post-merger HHIs would increase to highly concentrated levels of approximately 2750 points and 2080 points, respectively. The divestiture, however, significantly reduces these levels.
Effect of divestiture on ability and incentive profitably to withhold output and raise prices. Although the divestiture will substantially reduce market shares and concentration levels compared to the levels that would have prevailed absent divestiture, the purpose of the divestiture is to preserve competition, not merely maintain HHIs or market shares at their pre-merger levels. Accordingly, the proposed Final Judgment seeks to restore effective competition by depriving Exelon of key assets that would have made it profitable for it to withhold output and raise prices in PJM East and PJM Central/East. Divestiture of the six generating plants deprives the merged firm of key generating plants whose output it would otherwise have had the ability profitably to withhold. At the same time, the divestiture reduces the incentive the merged firm otherwise would have had to withhold output. In this way, the proposed Final Judgment assures that the merger is not likely to lead to consumer harm.

The proposed Final Judgment requires divestiture of generating units that would have significantly enhanced the merged firm’s ability profitably to withhold output. These units include all of the merged firm’s coal-fired steam units in PJM East and PJM Central/East (located at the Eddystone, Cromby, Hudson, and Sewaren plants); one of the merged firm’s two combined cycle units (located at the Linden plant); and several efficient peaking units (located at the Eddystone, Cromby, Linden, Hudson, and Sewaren plants). Because their operating costs are relatively close to clearing prices for a substantial number of hours during the year, the

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Post divestiture, Exelon will retain a significant amount of low-cost, baseload nuclear capacity. Although this capacity may provide Exelon with incentive to exercise market power by withholding output, the divestiture called for by the proposed Final Judgment substantially limits Exelon’s ability to withhold output. Moreover, it is not likely that Exelon will withhold output from nuclear units given the large opportunity cost – the lost profit on withheld nuclear output – of withholding.

Opportunity cost of withholding output from these units – the lost profit on withheld output from them – is relatively small. Without these units, Exelon will be left with few assets in PJM East and PJM Central/East that operate close to clearing prices for a substantial number of hours of the year. This will increase significantly the opportunity cost of withholding output and make it less likely to be profitable. Thus the divestiture will substantially limit the ability of the merged firm profitably to withhold output and thereby raise prices.

The divestiture will also reduce the merged firm’s incentive to withhold output and raise prices. Certain of the divested assets – the coal-fired steam and combined cycle units – have operating costs that are below the market clearing price for a substantial portion of the year and which therefore are frequently in a position to benefit from an increase in the market clearing price. Divestiture of these units will reduce the potential gains to the merged firm of withholding output and thus reduce the incentive of the merged firm to withhold output in the first place.

**Requirements regarding divestiture.** Defendants must take all reasonable steps necessary to accomplish the divestiture quickly and shall cooperate with prospective purchasers. Defendants must also provide acquirers information relating to personnel that are or have been involved, at any time since January 1, 2006, in the operation of, or provision of generation services by, the Divestiture Assets. Defendants further must refrain from interfering with any

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3 Post divestiture, Exelon will retain a significant amount of low-cost, baseload nuclear capacity. Although this capacity may provide Exelon with incentive to exercise market power by withholding output, the divestiture called for by the proposed Final Judgment substantially limits Exelon’s ability to withhold output. Moreover, it is not likely that Exelon will withhold output from nuclear units given the large opportunity cost – the lost profit on withheld nuclear output – of withholding.
negotiations by the acquirer or acquirers to employ any of the personnel that are or have been involved in the operation of any of the Divestiture Assets. Moreover, the proposed Final Judgment restricts Defendants from reacquiring any of the Divestiture Assets during the term of the proposed Final Judgment. Finally, the proposed Final Judgment requires that Defendants, with certain exceptions, obtain advance approval from the Department of Justice, for the entire duration of the Final Judgment, to acquire or enter into contracts to control any generating plants within the utility zones within PJM East or PJM Central/East.

B. **Use of a Divestiture Trustee**

In the event that Defendants do not accomplish the divestiture within the periods prescribed in the proposed Final Judgment, the proposed Final Judgment provides that the Court will appoint a trustee selected by the United States to effect the divestiture. If a trustee is appointed, the proposed Final Judgment provides that Defendants will pay all the costs and expenses of the trustee. The trustee’s commission will be structured so as to provide an incentive for the trustee based on the price obtained and the speed with which the divestiture is accomplished. After his or her appointment becomes effective, the trustee will file monthly reports with the Court and the United States setting forth his or her efforts to accomplish the divestiture. At the end of sixty (60) days, if the divestiture has not been accomplished, the trustee and the United States will make recommendations to the Court, which shall enter such orders as appropriate to carry out the purpose of the trust, including extending the trust or the term of the trustee’s appointment.
IV. EXPLANATION OF THE HOLD SEPARATE STIPULATION AND ORDER

The Stipulation entered into by the United States and Defendants ensures that the Divestiture assets are preserved and maintained and that competition is maintained during the pendency of the ordered divestiture. First, the Stipulation includes terms requiring that Defendants maintain the Divestiture Assets as economically viable and competitive facilities. Second, the Stipulation includes terms ensuring that Defendants do not withhold output from the wholesale electricity market. In particular, the Stipulation requires that Defendants offer the output from certain generating units that they continue to own after consummation for sale into the PJM auctions at no more than specified price levels until the Divestiture Assets are sold. The Stipulation also calls for appointment of an auditor to ensure that Defendants offer their units at no more than the specified price levels and that they do not withhold the output of generating units to raise prices. These requirements seek to ensure that Defendants will not offer their units into the PJM auctions in a way that allows Defendants to raise the market clearing price.

Requiring Defendants to hold the Divestiture Assets separate and distinct, a typical requirement in Antitrust Division hold separate stipulation and orders, would not have prevented competitive harm in the interim period from consummation to divestiture. The operator of the Divestiture Assets would have recognized that reducing their output would increase the clearing price and benefit Defendants’ remaining generating units. Therefore, the Stipulation requires that Defendants maintain offers for output of the Divestiture Assets at the specified levels. Defendants are relieved of the requirement to offer their units at no more than specified levels if
they transfer to a third party the rights to offer and receive the revenues from the sale of the complete output of the Divestiture Assets.

V. REMEDIES AVAILABLE TO POTENTIAL PRIVATE LITIGANTS

Section 4 of the Clayton Act, 15 U.S.C. § 15, provides that any person who has been injured as a result of conduct prohibited by the antitrust laws may bring suit in federal court to recover three times the damages the person has suffered, as well as costs and reasonable attorneys’ fees. Entry of the proposed Final Judgment will neither impair nor assist the bringing of any private antitrust damage action. Under the provisions of Section 5(a) of the Clayton Act, 15 U.S.C. § 16(a), the proposed Final Judgment has no prima facie effect in any subsequent private lawsuit that may be brought against Defendants.

VI. PROCEDURES AVAILABLE FOR MODIFICATION OF THE PROPOSED FINAL JUDGMENT

The United States and Defendants have stipulated that the proposed Final Judgment may be entered by the Court after compliance with the provisions of the APPA, provided that the United States has not withdrawn its consent. The APPA conditions entry upon the Court’s determination that the proposed Final Judgment is in the public interest.

The APPA provides a period of at least sixty (60) days preceding the effective date of the proposed Final Judgment within which any person may submit to the United States written comments regarding the proposed Final Judgment. Any person who wishes to comment should
do so within sixty (60) days of the date of publication of this Competitive Impact Statement in the Federal Register. All comments received during this period will be considered by the Department of Justice, which remains free to withdraw its consent to the proposed Final Judgment at any time prior to the Court’s entry of judgment. The comments and the response of the United States will be filed with the Court and published in the Federal Register.

Written comments should be submitted to:

Donna N. Kooperstein  
Chief, Transportation, Energy & Agriculture Section  
Antitrust Division  
United States Department of Justice  
325 Seventh Street, NW, Suite 500  
Washington, DC 20530

The proposed Final Judgment provides that the Court retains jurisdiction over this action, and the parties may apply to the Court for any order necessary or appropriate for the modification, interpretation, or enforcement of the Final Judgment.

VII. ALTERNATIVES TO THE PROPOSED FINAL JUDGMENT

The United States considered, as an alternative to the proposed Final Judgment, a full trial on the merits against Defendants. The United States could have continued the litigation and sought preliminary and permanent injunctions against Exelon’s acquisition of certain PSEG assets. The United States is satisfied, however, that the divestiture of assets described in the
In 2004, Congress amended the APPA to ensure that courts take into account the above-quoted list of relevant factors when making a public interest determination. Compare 15 U.S.C. § 16(e) (2004) with 15 U.S.C. § 16(e)(1) (2006) (substituting “shall” for “may” in directing relevant factors for court to consider and amending list of factors to focus on competitive considerations and to address potentially ambiguous judgment terms). This amendment does not affect the substantial precedent in this and other Circuits analyzing the scope and standard of review for Tunney Act proceedings.

The proposed Final Judgment will preserve competition in the market for wholesale electricity in PJM East and PJM Central/East.

VIII. STANDARD OF REVIEW UNDER THE APPA
FOR THE PROPOSED FINAL JUDGMENT

The APPA requires that proposed consent judgments in antitrust cases brought by the United States be subject to a sixty (60) day comment period, after which the Court shall determine whether entry of the proposed Final Judgment “is in the public interest.” 15 U.S.C. § 16(e)(1). In making that determination, the Court shall consider:

(A)  the competitive impact of such judgment, including termination of alleged violations, provisions for enforcement and modification, duration of relief sought, anticipated effects of alternative remedies actually considered, whether its terms are ambiguous, and any other competitive considerations bearing upon the adequacy of such judgment that the court deems necessary to a determination of whether the consent judgment is in the public interest; and

(B)  the impact of entry of such judgment upon competition in the relevant market or markets, upon the public generally and individuals alleging specific injury from the violations set forth in the complaint including consideration of the public benefit, if any, to be derived from a determination of the issues at trial.

15 U.S.C. § 16(e)(1)(A) & (B). As the United States Court of Appeals for the District of Columbia Circuit has held, under the APPA a court considers, among other things, the

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In 2004, Congress amended the APPA to ensure that courts take into account the above-quoted list of relevant factors when making a public interest determination. Compare 15 U.S.C. § 16(e) (2004) with 15 U.S.C. § 16(e)(1) (2006) (substituting “shall” for “may” in directing relevant factors for court to consider and amending list of factors to focus on competitive considerations and to address potentially ambiguous judgment terms). This amendment does not affect the substantial precedent in this and other Circuits analyzing the scope and standard of review for Tunney Act proceedings.
relationship between the remedy secured and the specific allegations set forth in the
government’s complaint, whether the decree is sufficiently clear, whether enforcement
mechanisms are sufficient, and whether the decree may positively harm third parties. See United

With respect to the adequacy of the relief secured by the decree, a court may not “engage
in an unrestricted evaluation of what relief would best serve the public.” United States v. BNS,
Inc., 858 F.2d 456, 462 (9th Cir. 1988) (citing United States v. Bechtel Corp., 648 F.2d 660, 666
(9th Cir. 1981)); see also Microsoft, 56 F.3d at 1460-62. Courts have held that:

[t]he balancing of competing social and political interests affected by a proposed
antitrust consent decree must be left, in the first instance, to the discretion of the
Attorney General. The court’s role in protecting the public interest is one of
insuring that the government has not breached its duty to the public in consenting
to the decree. The court is required to determine not whether a particular decree is
the one that will best serve society, but whether the settlement is “within the
reaches of the public interest.” More elaborate requirements might undermine the
effectiveness of antitrust enforcement by consent decree.

Bechtel, 648 F.2d at 666 (emphasis added) (citations omitted).5 In making its public interest
determination, a district court must accord due respect to the government’s prediction as to the

5 Cf. BNS, 858 F.2d at 464 (holding that the court’s “ultimate authority under the [APPA]
is limited to approving or disapproving the consent decree”); United States v. Gillette Co., 406 F.
Supp. 713, 716 (D. Mass. 1975) (noting that, in this way, the court is constrained to “look at the
overall picture not hypercritically, nor with a microscope, but with an artist’s reducing glass”);
see generally Microsoft, 56 F.3d at 1461 (discussing whether “the remedies [obtained in the
decree are] so inconsonant with the allegations charged as to fall outside of the ‘reaches of the
public interest’”).

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Court approval of a final judgment requires a standard more flexible and less strict than the standard required for a finding of liability. “[A] proposed decree must be approved even if it falls short of the remedy the court would impose on its own, as long as it falls within the range of acceptability or is ‘within the reaches of public interest.’” *United States v. Am. Tel. & Tel. Co.*, 552 F. Supp. 131, 151 (D.D.C. 1982) (citations omitted) (quoting *United States v. Gillette Co.*, 406 F. Supp. 713, 716 (D. Mass. 1975)), aff’d sub nom. *Maryland v. United States*, 460 U.S. 1001 (1983); see also *United States v. Alcan Aluminum Ltd.*, 605 F.Supp. 619, 622 (W.D. Ky. 1985) (approving the consent decree even though the court would have imposed a greater remedy).

Moreover, the Court’s role under the APPA is limited to reviewing the remedy in relationship to the violations that the United States has alleged in its Complaint, and does not authorize the Court to “construct [its] own hypothetical case and then evaluate the decree against that case.” *Microsoft*, 56 F.3d at 1459. Because the “court’s authority to review the decree depends entirely on the government’s exercising its prosecutorial discretion by bringing a case in the first place,” it follows that “the court is only authorized to review the decree itself,” and not to “effectively redraft the complaint” to inquire into other matters that the United States did not pursue. *Id.* at 1459-60.
In its 2004 amendments to the Tunney Act, Congress made clear its intent to preserve the practical benefits of utilizing consent decrees in antitrust enforcement, adding the unambiguous instruction “[n]othing in this section shall be construed to require the court to conduct an evidentiary hearing or to require the court to permit anyone to intervene.” 15 U.S.C. § 16 (e)(2). This language codified the intent of the original 1974 statute, expressed by Senator Tunney in the legislative history: “[t]he court is nowhere compelled to go to trial or to engage in extended proceedings which might have the effect of vitiating the benefits of prompt and less costly settlement through the consent decree process.” 119 Cong. Rec. 24,598 (1973) (statement of Senator Tunney). Rather:

[a]bsent a showing of corrupt failure of the government to discharge its duty, the Court, in making its public interest finding, should . . . carefully consider the explanations of the government in the competitive impact statement and its responses to comments in order to determine whether those explanations are reasonable under the circumstances.

IX. DETERMINATIVE DOCUMENTS

There are no determinative materials or documents within the meaning of the APPA that were considered by the United States in formulating the proposed Final Judgment.

Dated: August 10, 2006

Respectfully submitted,

/s/
Mark J. Niefer (DC Bar #470370)
Jade Alice Eaton (DC Bar #939629)
Tracy Lynn Fisher (MN Bar #315837)
CERTIFICATE OF SERVICE

I hereby certify that on August 10, 2006, I caused a copy of the foregoing Competitive Impact Statement to be served on counsel for Defendants in this matter in the manner set forth below:

By electronic mail and hand delivery:

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ORDER AUTHORIZING MERGER UNDER SECTION 203 OF THE FEDERAL POWER ACT

(Issued July 1, 2005)

1. In this order, the Commission authorizes the merger of Exelon Corporation (Exelon) and Public Service Enterprise Group Incorporated (PSEG Holdings) (collectively, Applicants) to form Exelon Electric & Gas Corporation (EE&G). This order benefits customers because it ensures that the transaction, which includes mitigation of market effects through very substantial divestiture of generation, is consistent with the public interest, as required by section 203 of the Federal Power Act\(^1\) (FPA).

Background

A. The Parties

2. Exelon is a registered holding company, under the Public Utility Holding Company Act of 1935 (PUHCA)\(^2\) that distributes electricity to approximately 5.1 million customers in Illinois and Pennsylvania through its subsidiaries, mainly Commonwealth Edison (ComEd) and PECO Energy (PECO). Through ComEd and PECO, it is the Provider of Last Resort (POLR) for customers who do not or cannot exercise retail choice for their electricity needs in Illinois and Pennsylvania, respectively. Exelon is also involved in gas distribution through PECO. The PECO gas facilities are local distribution facilities that are not interstate facilities and, therefore, are not subject to the

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\(^1\) 16 U.S.C. § 824(b) (2000).

Commission’s jurisdiction under the Natural Gas Act. Exelon Generation Company, LLC (Exelon Generation) conducts Exelon’s generation business. Exelon Generation owns or controls generation assets throughout the country with a net capacity of approximately 33,000 MWs, including ownership interests in 11 nuclear generating stations.

3. PSEG Holdings is an exempt public utility holding company, under PUHCA, with four major subsidiaries, including Public Service Electric and Gas Company (PSE&G), which is a public utility company engaged in the transmission and distribution of electric energy and gas service to approximately 3.6 million customers, primarily in New Jersey. PSEG Holdings’ subsidiaries also include PSEG Power LLC, the parent company of most of PSEG’s United States power production business, PSEG Services Corporation, and PSEG Energy Holdings LLC, the parent company of PSEG’s other businesses.

4. Both Exelon and PSEG Holdings have transferred control of their transmission systems to the PJM Interconnection, LLC (PJM), a Commission approved Regional Transmission Organization (RTO). Both entities sell power under market-based rate authority.

B. The Proposed Transaction

5. On February 4, 2005, Exelon and PSEG Holdings filed, under section 203 of the FPA and Part 33 of the Commission’s Regulations, an application for Commission approval of a transaction that includes: (1) Exelon’s acquisition of PSEG Holdings and the resulting indirect merger of Exelon’s and PSEG Holdings’ jurisdictional facilities; and (2) the internal restructuring and consolidation of Exelon’s and PSEG Holdings’ subsidiaries to establish an efficient corporate structure for EE&G.

6. PSEG Holdings would no longer have a separate corporate existence and would merge into Exelon, forming EE&G. PSEG Holdings’ shareholders would each receive 1.225 shares of Exelon common stock for each PSEG Holdings share held and cash in

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3 Application at 7.


5 Applicants submitted an errata to their application on February 9, 2005.

lieu of any fraction of an Exelon share that a PSEG shareholder would have otherwise been entitled to receive. EE&G will remain the ultimate corporate parent of PECO and ComEd and other Exelon subsidiaries and will become the corporate parent of PSE&G and all other PSEG subsidiaries. EE&G will assume all of PSEG Holdings’ outstanding indebtedness.

7. EE&G will be a registered public utility holding company under PUHCA. ComEd, PECO and PSE&G will continue to operate franchised public utility companies.

8. In addition to merging jurisdictional assets, Applicants intend to revise their corporate structure. They plan to make PSE&G a direct subsidiary of Exelon Energy Delivery Company LLC and keep the subsidiaries of PSE&G intact. PSEG Energy Holdings LLC will become a direct subsidiary of EE&G and the subsidiaries of PSEG Holdings LLC will remain intact. The PSEG Services Corporation will sell all of its assets to Exelon Business Services Company, making Exelon Business Services Company the sole “service company” of EE&G. PSEG Power and its direct subsidiaries, PSEG Nuclear, PSEG Fossil and PSEG Energy Resources and Trade, would all become part of Exelon Generation, and their business functions would become part of their respective Exelon Generation business units. The subsidiaries owned by PSEG Power, PSEG Nuclear, PSEG Fossil and PSEG Energy Resources and Trade, will either be merged into Exelon Generation or kept as direct subsidiaries of Exelon Generation. The reorganization will not result in merchant affiliates that have market-based rate authority being moved back into the regulated companies of EE&G.

9. Applicants state that the proposed merger will benefit the public interest by providing an increased scale and scope of both energy delivery and generation, improved service and reliability, and a more balanced generation portfolio to serve over seven million electric customers and two million gas customers. Applicants’ further state that the proposed merger will lead to improved stability, higher capacity utilization rates and lower costs from combining the nuclear operations under Exelon’s experienced management.

C. **Standard of Review under Section 203**

10. Section 203(a) provides that the Commission must approve a merger if it finds that the consolidation “will be consistent with the public interest.”\(^7\) The Commission’s analysis under the Merger Policy Statement of whether a consolidation is consistent with the public interest generally involves consideration of three factors: (1) the effect on

\(^7\) *Id.*
As discussed below, we will approve the proposed merger as consistent with the public interest and find that it will not adversely affect competition, rates, or regulation.

1. Effect on Competition

a. Applicants’ Analysis of Horizontal Competitive Issues

11. Exelon retained Dr. William Hieronymus and PSEG Holdings retained Mr. Rodney Frame to analyze the effect of the merger on competition. Both witnesses identify three relevant products: non-firm energy, capacity, and ancillary services, across the geographic markets affected by the merger. Both witnesses conclude that, as mitigated, the merger will not harm competition.

i. Energy Markets

12. Dr. Hieronymus identifies four relevant geographic markets using the approach described by Appendix A of the Merger Policy Statement: Expanded PJM, PJM Pre-2004, PJM East, and Northern PSEG. In his analysis of non-firm energy markets, Dr. Hieronymus uses economic capacity and Available Economic Capacity, as defined in the Merger Policy Statement, as proxies to represent a supplier’s ability to participate in the...
market. He uses the Delivered Price Test to evaluate the effect on competition in the relevant markets over 10 separate time periods: Super Peak, Peak and Off-Peak periods for Summer, Winter and Shoulder seasons, along with an extreme Summer Super Peak. Dr. Hieronymus uses a range of prices from $20 per megawatt hour (MWh) in the Shoulder Off-Peak to $250 per MWh in the extreme Summer Super Peak. He considers actual prices in the PJM markets during 2004, fuel prices in 2004, and forecast fuel prices for 2006, the test year for his analysis.

13. In his analysis, Dr. Hieronymus presumes simultaneous import limits for imports into each geographic market based on a study conducted by PSE&G’s transmission engineering group. The simultaneous import limits in his analysis are 7,300 MW for PJM-East; 4,600 MW for PJM Pre-2004; and 7,500 MW for Expanded PJM. Dr. Hieronymus allocates scarce transmission availability on a pro rata basis.

14. Dr. Hieronymus states that Exelon has several long-term contracts that are relevant to the analysis. Exelon has long-term contracts to purchase the output of two coal-fired generating plants and approximately 3,600 MW of supply from peaking facilities, all in the ComEd service territory. Dr. Hieronymus assigns control of that capacity to Exelon. Exelon sells 400 MW of the output of the Clinton nuclear unit under a long-term contract, and Dr. Hieronymus assigns control of that capacity to the buyer. He states that PSE&G has sold a substantial amount of energy and capacity in the New Jersey Basic Generation Service auction. He assigns control of that capacity to PSE&G. He does, however, consider those commitments as part of PSE&G’s native load deduction in his analysis of Available Economic Capacity.

15. Without mitigation, Dr. Hieronymus reports failures of the Competitive Analysis Screen for economic capacity in all season/load conditions in PJM East, PJM Pre-2004, and Expanded PJM. For PJM-East, the screen failures are most severe, with post-merger market concentrations ranging from 2,057 to 2,492 on the Herfindahl-Hirschman Index (HHI) (indicating a highly concentrated market) and merger-related changes in HHI ranging from 848 to 1,067 HHI, all well above the 50 HHI screening threshold for highly concentrated markets.

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10 Each supplier’s “economic capacity” is the amount of capacity that could compete in the relevant market given market prices, running costs, and transmission availability. “Available Economic Capacity” is based on the same factors but subtracts the suppliers’ native load obligation from its capacity and adjusts transmission availability accordingly.

11 Hieronymus Testimony, Exhibit J-1, at 37.

12 Merger Policy Statement, Appendix A at 30,128 (Competitive Analysis Screen).
concentrated markets. As stated in the Merger Policy Statement, for moderately concentrated markets (1000 ≤ HHI < 1800), the screening threshold for the change in HHI is 100. For the PJM Pre-2004 and Expanded PJM markets, the post-merger HHIs indicate moderately concentrated markets, with merger-related increases in HHI ranging from 172 to 668 HHI, all above the 100 HHI screening threshold for moderately concentrated markets.

16. For the other markets that could be affected by the merger, Northern PSEG, Electric Reliability Counsel of Texas (ERCOT) and ISO New England, Inc. (ISO-NE), Dr. Hieronymus does not perform a complete competitive screen analysis, but explains why he thinks such an analysis is not necessary and why the merger will not harm competition in those markets.

17. For Northern PSEG, Dr. Hieronymus argues that because Exelon does not own any generation in that market, the merger will not harm competition. He states that when there are not binding transmission constraints for imports into Northern PSEG, the geographic boundaries of the market are at least as broad as PJM-East, and he states that Applicants’ proposed mitigation will offset any increase in market concentration in that market.\textsuperscript{13} He argues that when there are import constraints for Northern PSEG, it should be considered a separate market from PJM East. However, in that case, the merger will not increase the amount of capacity controlled by the merged firm or its incentive to withhold generation to raise prices, because Exelon does not own any capacity in Northern New Jersey, so there is no overlap between the Exelon and PSE & G’s generation capacity in that market. Despite his argument, Dr. Hieronymus does analyze Northern PSEG and shows screen failures due to some of Exelon’s capacity being included in the \textit{pro rata} allocation of transmission availability. His analysis shows post-merger concentrations ranging from 2,750 to 7,288 HHI, with merger-related increases in concentration ranging from 99 to 204 HHI. He finds that divesting 100 MW of generating capacity in Northern PSEG would return market concentration levels to approximately the pre-merger levels, with the concentration increasing by less than 50 HHI for some load levels and falling in others. He states that if the Commission decides it is necessary to mitigate the screen failures, Applicants would divest sufficient generation in the Northern PSEG market as part of their overall divestiture plan.

18. Dr. Hieronymus argues that there is little overlap between Exelon and PSE & G’s generation assets in the ERCOT market. He states that Exelon owns or controls 3,651 MW of generation capacity, mostly in the North zone of ERCOT, while PSE & G owns 2,026 MW of affiliated generation capacity in the West and South zones. He argues that because Applicants’ capacity is in different zones within ERCOT, the only market that

\textsuperscript{13} Northern PSEG is a subset of PJM-East.
could be affected by the merger is ERCOT as a whole. He states that Exelon and PSE&G’s capacity in ERCOT is less than five percent and 2.5 percent respectively, so the merger-related change in HHI would only be approximately 20 HHI, well under Commission’s screening threshold.\textsuperscript{14}

19. For the ISO-NE market, Dr. Hieronymus also argues that, because Exelon’s and PSE&G’s generation is in different constrained regions, the smallest relevant market in which both Applicants’ generation would compete would be ISO-NE as a whole. He concludes that because Exelon and PSE&G control only two and three percent of the generation capacity in ISO-NE, combining such small market shares would not harm competition.\textsuperscript{15}

20. PSE&G’s witness, Mr. Frame, also analyzes non-firm energy markets, using economic capacity and Available Economic Capacity to represent a supplier’s ability to participate in the market. Mr. Frame analyzes three geographic markets using the approach described by Appendix A of the Merger Policy Statement: Expanded PJM, PJM Pre-2004, PJM East. He uses the Delivered Price Test to analyze the effect of the merger on market concentration. Like Dr. Hieronymus, Mr. Frame uses ten season/load conditions. He uses a range of prices from $30 to $150 per MWh based on prevailing market-clearing prices in PJM over the last two years for the relevant season/load conditions. He allocates scarce transmission availability on a pro rata basis and imposes simultaneous imports limitations in his analysis. Mr. Frame states that he follows the Commission’s procedures by assigning control of generation under contract to the party that has operational control of the facility.

21. Mr. Frame’s results are consistent with those of Dr. Hieronymus. He reports screen failures in PJM-East and Pre-2004 PJM for all season/load conditions, and in Expanded PJM for most season/load conditions. For PJM-East, he reports post-merger

\textsuperscript{14} Dr. Hieronymus refers to the “2ab” change in HHI, which is derived from the difference between adding the squares of the pre-merger market shares of the two firms ($a^2 + b^2$), and squaring the combined firm’s post-merger market share ($\left( a+b \right)^2 = a^2 + b^2 + 2ab$). The term is commonly used in analyses of changes in market structure.

\textsuperscript{15} Dr. Hieronymus cites the Commission’s finding in \textit{USGen New England, Inc.}, 109 FERC \textsuperscript{\$} 61,341 (2004), where the Commission approved the purchase of approximately 7 percent of the capacity in ISO-NE by a company that already controlled approximately 6 percent of the capacity in ISO-NE. A “2ab” analysis of combining Exelon’s and PSEG’s capacity in ISO-NE would lead to an increase of approximately 12 HHI, well below the screening thresholds of 50 HHI for highly concentrated markets and 100 HHI for moderately concentrated markets.
concentrations ranging from 1,688 to 2,816 HHI, with merger-related changes in HHI ranging from 695 to 1,252 HHI, all well above the Commission’s screening thresholds. For Pre-2004 PJM, he reports post-merger concentrations ranging from 1,133 to 1,509 HHI, with merger-related changes in HHI ranging from 336 to 443 HHI, all well above the Commission’s screening thresholds. For Expanded PJM, he reports post-merger concentrations ranging from 919 to 1,197 HHI, with merger related changes in HHI ranging from 178 to 236 HHI, with six of the ten season/load conditions above the Commission’s screening thresholds.

22. Dr. Hieronymus also performs a Competitive Analysis Screen for Available Economic Capacity in Expanded PJM, PJM Pre-2004, PJM East, and Northern PSEG. However, he argues that Available Economic Capacity is not an accurate measure in PJM because utilities have been largely released from their native load obligations in states with retail choice programs; or serve as providers of last resort through power purchase agreements, or, in the case of New Jersey, through the Basic Generation Service auction. He reports screen failures in eight of the 10 season/load conditions in PJM East, all season/load conditions in PJM Pre-2004, and none of the season/load levels for Expanded PJM.

23. Mr. Frame also performs a Competitive Analysis Screen for Available Economic Capacity in Expanded PJM, PJM Pre-2004, and PJM East. He states that Available Economic Capacity is difficult to measure in PJM because native load obligations have changed in states with retail choice programs, standard offer services and Basic Generation Service auctions. He states that the purpose of his Available Economic Capacity analysis is to show that the mitigation offered to address the screen failures in the Economic Capacity analysis will mitigate any Available Economic Capacity screen violation. He states that he uses conservative assumptions for his Available Economic Capacity analysis and reports screen failures for most season/load conditions for those markets, all of which are eliminated by the mitigation.

24. Like Dr. Hieronymus, Mr. Frame argues that it is not necessary to analyze the effect of the merger on competition in the Northern New Jersey market because Exelon does not own any generation in that market. He does, however, analyze Northern New Jersey by starting with his analysis of the PJM East market, removing suppliers located in

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16 Under the scenario where only the PECO and PSE&G loads are taken into account, there are no screen failures. However, when all PJM Pre-2004 loads are considered, there are screen failures in all seasons. According to Dr. Hieronymus, this assumption is not critical to the outcome of his analysis because the mitigation for the screen failures in economic capacity more than offsets the increases in concentration in Available Economic Capacity under either assumption.
Northern New Jersey, and then allocating the import capability into Northern New Jersey among the PJM East suppliers. He states that based on his analysis, divesting approximately 100 MW of generation capacity, including at least 80 MW of coal-fired capacity within Northern New Jersey, would eliminate any screen violations in the Northern New Jersey Market.

**ii. Mitigation for identified screen failures**

25. Applicants propose mitigation to address the harm to competition indicated by the screen failures. First, they propose divesting 2,900 MW of generation capacity in PJM-East in order to eliminate the peak and super-peak screen failures described above. The 2,900 MW would consist of 1,000 MW of peaking generation and 1,900 MW of mid-merit generation, of which at least 550 MW would be coal-fired capacity. They state that no more than half of the 2,900 MW would be sold to a single buyer and that no capacity would be sold to a market participant with a greater than five percent market share in PJM-East or Expanded PJM (original Buyer Restrictions). Applicants note that they have not yet identified the specific generation units that they intend to divest. They do, however, list those generating units that will be considered for divestiture. Applicants also state they will make a compliance filing showing the effect on market concentration given the actual divestitures.

26. Applicants originally committed to complete the divestiture within 18 months after the date of merger consummation, but later committed to complete the divestiture within 12 months. They recognize that the Commission requires that interim mitigation for any merger-related harm to competition be in place at the time of merger consummation. Accordingly, they propose that within 30 days following the end of the month in which the merger closes, they will sell the rights to 2,900 MW of energy and capacity from

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17 Frame Testimony at 39-40.

18 Applicants’ original commitment was designed to ensure that the divestiture will reduce market concentration enough to eliminate the harm to competition indicated by the screen failures. If, for example, the capacity were sold to an existing market participant with a large market share, or if all of the capacity were sold to a single buyer, the divestiture would not restore market concentration to a level close to the pre-merger concentration. Applicants subsequently revised their mitigation proposal, eliminating most of the Buyer Restrictions.

19 Application, Exhibit J-12.

20 Answer at 47.
designated coal, mid-merit and peaking facilities in PJM–East.\textsuperscript{21} As with the permanent mitigation, they state that no more than half of the 2,900 MW would be sold to a single buyer and that no capacity would be sold to a market participant with a greater than five percent market share in PJM-East of Expanded PJM. The interim contracts will have a minimum term of one month and will be in effect for no longer than 18 months after merger consummation. Applicants explain that the purchasers of the interim capacity and energy will acquire all of the Unforced Capacity associated with the units, and full dispatch unit and offering rights, including the right to call for market-based ancillary services, thus enabling the purchaser to offer the units into the PJM capacity, energy and ancillary services markets.\textsuperscript{22}

27. Applicants propose a “virtual divestiture” to address the Appendix A screen failures for the off-peak periods. They will sell long-term energy rights from nuclear baseload units.\textsuperscript{23} They state that the virtual divestiture will remove any merger-related increase in Applicants’ ability or incentive to withhold baseload energy in order to exercise market power. Applicants propose virtually divesting 2,250 MW of energy from nuclear units located in PJM-East in order to address the screen failures in that market.\textsuperscript{24} They note that Dr. Hieronymus’ analysis shows that an additional divestiture of 200 MW of capacity in the larger Pre-2004 PJM market is also required and, accordingly, they will virtually divest another 200 MW of baseload nuclear energy in the larger, Pre-2004 PJM market.

28. Applicants state that the virtual divestiture will take one of two forms: (1) a firm sales contract expiring no earlier than 15 years after the date of the merger consummation (Long-Term Contract Option); or (2) an annual auction of 3-year entitlements to baseload energy, in 25 MW blocks. Applicants state that the auction process will be administered

\textsuperscript{21} Application at 34.

\textsuperscript{22} Cassidy testimony at 6.

\textsuperscript{23} The energy sales are not meant to address the identified screen failures in the capacity markets; rather, they target the off-peak energy screen failures described above. Applicants have provided a separate mitigation plan for capacity markets, which is described later in this order.

\textsuperscript{24} Exelon’s witness, Dr. Hieronymus, identified the need to divest 2,400 MW of baseload capacity in order to restore competition in PJM-East. Applicants argue that “virtually” divesting 2,250 MW on a 100 percent load factor basis is the “energy equivalent” of selling 2,400 MW of capacity operating at Exelon’s historical capacity factor of 93 percent. Application at 24.
by an independent auction manager in order to ensure a transparent and objective auction process. The sum of the baseload energy entitlements sold under the two options will be 2,450 MW (Baseload Mitigation Amount), unless, as described below, the Baseload Mitigation Amount needed to mitigate harm is reduced by other structural mitigation measures. In addition, no single purchaser will be allowed to purchase more than 50 percent of the Baseload Mitigation Amount.

29. Applicants state that under the Long-Term Contract Option, they will sell entitlements to PJM East baseload nuclear energy for terms of at least 15 years in return for cash or similar rights to energy taken for delivery outside of PJM (Energy Swap). Applicants originally committed to the divestiture restrictions regarding the potential purchasers under the Long-Term Contract Option, and, additionally, committed that they will not sell more that 25 percent of the Baseload Mitigation Amount to market participants owning three to five percent of the installed generation capacity in Expanded PJM or PJM East.

30. Applicants state that, under the auction option, the auctions will be held to coincide with the New Jersey Basic Generation Service auctions. The product to be auctioned will be a three-year obligation to take 25 MW of “7 x 24” energy. In the first year, the auction will be phased in by selling one third of the capacity for a one-year term, one third of the capacity for a two-year term, and one third of the capacity for a three-year term. In subsequent years, one third of the capacity will be sold for a three-year term.

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25 Cassidy Testimony at 14.

26 Applicants argue that this additional condition is to ensure that the virtual divesture will sufficiently mitigate the harm to competition indicated by the off-peak screen failures.

27 As constructed, the Auction Amount will be under contract at all times. For example, assuming the Auction Amount were 1,500 MW in the first year (in that case 2,250 MW minus 750 MW under the Long-Term Contract Option), 500 MW would be under one-year contracts, 500 MWs would be under the first year of two-year contracts, and 500 MWs would be under the first year of three-year contracts. In the second year, 500 MWs would be under the second year of two-year contracts, 500 MW would be under the second year of three-year contracts, and the 500 MWs that expired under the initial one-year contracts would be in the first year of new, three-year contracts. So each year, one third of the existing contracts expire and are replaced by new three-year contracts.
31. Dr. Hieronymus analyzes the effect of the merger, given Applicants’ proposed mitigation, and finds that the merger would not harm competition. For PJM-East, the merger-related changes in concentration range from falling by 101 HHI in the Winter Peak period to rising by 63 HHI in the Winter Super Peak period. The post-merger and mitigation markets are moderately concentrated for all season/load conditions, with the change in market concentration falling within the Commission’s tolerance for all periods. For PJM Pre-2004 and PJM Expanded, with mitigation, the markets are moderately concentrated in 14 of the 20 total season/load conditions and unconcentrated in the other 6 season/load conditions. With exception of one season/load condition in each market, all of the changes in concentration are within the Commission’s tolerances. Dr. Hieronymus concludes that Applicants’ proposed mitigation eliminates any harm to competition indicated by the screen failures in his analysis of economic capacity. In addition, the proposed mitigation would reduce market concentration below the pre-merger level in the three PJM markets in all season/load conditions for Available Economic Capacity. Therefore, he also concludes that the proposed mitigation eliminates any harm to competition indicated by the screen failures in his analysis of Available Economic Capacity.

32. Mr. Frame also finds that the proposed mitigation would eliminate the harm to competition in energy markets indicated by the screen failures in economic and Available Economic Capacity. Mr. Frame finds that the proposed mitigation would reduce market concentration below the pre-merger level in the three PJM markets in virtually all season/load condition for Available Economic Capacity. For economic capacity, he finds that the post-merger and mitigation markets will be moderately concentrated for 15 of the 30 season/load condition in the three PJM market scenarios and unconcentrated for the other 15 season/load conditions, with all changes in HHI falling within the Commission’s tolerance levels.

Notice of Filing and Pleadings

33. Notice of Applicants’ filing was published in the Federal Register, with interventions and protests due on or before April 11, 2005. Numerous parties filed motions to intervene. The Pennsylvania Public Utility Commission, the New Jersey

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29 NRG Power Marketing, Inc., Arthur Kill Power, LLC, Astoria Gas Turbine Power, LLC, Vienna Power, LLC, and Indian River Power LLC (collectively NRG Companies); Dynegy Power Corp. (Dynegy); Consolidated Edison Company of New York (ConEd NY); Reliant Energy, Inc. (Reliant); Amerada Hess Corporation (Hess); New Athens Generating Company (New Athens); Strategic Energy, LLC (Strategic); LS
117. Likewise, Applicants state that FirstEnergy’s supplemental affidavit from Ms. Frayer presents a new study of the effect of the merger on energy markets that does not respond to the Applicants’ revised mitigation proposal. They state that Ms. Frayer analyzed a higher price for various market conditions, thus including more generation in her analysis than did Dr. Hieronymus. However, Ms. Frayer neglected to take into account, when assessing Applicants’ mitigation proposal, additional divested generation that is economic at higher prices. Applicants conclude that this results in a systematic understatement of the effectiveness of the mitigation they offer.

118. Applicants respond to FirstEnergy’s and the PPL Companies’ claim that Applicants’ commitment to fund additional transmission expansion projects is just a commitment to do what they are already required to do under PJM’s Regional Transmission Planning Process. They point out that one of the projects to which they commit is on the list of projects required by the Regional Transmission Planning Process, but that they are committing to accelerate the project so that it will be in service a year earlier than required by the Regional Transmission Planning Process. Applicants note that the other projects they propose are or will be on PJM’s Economic Project list and that transmission owners are under no obligation to go forward with projects on this list. In response to concerns raised by H-P Energy that the Applicants may fund projects that H-P Energy already is pursuing, Applicants commit to not attempt to supplant any of the three projects identified by H-P Energy.

Discussion

119. Pursuant to Rule 214 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2004), the timely, unopposed motions to intervene serve to make the entities that filed them parties to the proceeding. We will grant Allegheny Electric, H-P Energy and the Indiana Utility Regulatory Commission’s motions to intervene out-of-time, since we find that doing so will not unduly disrupt the proceeding or place an undue burden on the parties. Rule 213(a)(2) of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2004), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept the answers filed herein because they have provided information that assisted us in our decision-making process.

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86 Id. at 18.

87 Applicants’ Answer 2 at p. 19.
120. Applicants have shown that the merger, with the mitigation proposed, will not harm competition in any relevant energy market. We find that Applicants’ revised mitigation proposal, which increases the total mitigation from 5,500 to 6,600 MW and removes almost all of the restrictions on who can buy the assets, addresses the competitive concerns raised by intervenors.

A. Adequacy of Applicants’ Analysis

121. Applicants have corrected the factual errors in their original analysis that commenters identified. This does not materially alter the results. We note that none of the protestors that identified the factual errors in Applicants’ original analysis argue that Applicants did not correct those errors.

122. We are not convinced by Applicants’ argument that Northern New Jersey is not a relevant geographic market. As noted by the PHI Companies and others, there are times when transmission constraints bind, leaving Northern New Jersey isolated from the rest of PJM-East. However, we agree with Applicants that, during those periods, the merger would not harm competition because Exelon does not have any generating facilities that would be combined with PSE&G’s existing generation in that load pocket. We note that there are times when imports from the rest of PJM East, where Exelon does own significant generating resources, would result in a merger-related increase in concentration due to Exelon’s share of the pro rata transmission allocation. In those cases, there are screen failures in the Northern PSEG market. We note Applicants have committed to mitigate all screen failures. We also note that Dr. Hieronymus’ testimony indicates that a 100 MW divestiture of generation capacity located in Northern PSE&G, along with the proposed mitigation for the PJM East market, is necessary to fully mitigate the merger-related increase in market concentration in Northern PSE&G. While Applicants have not explicitly committed to divesting 100 MW of generation located within Northern PSE&G, we consider the two statements above to be a commitment to do so, and we rely on that commitment in finding that the merger will not adversely affect competition in the Northern PSEG wholesale electricity market.\(^8^8\).

123. We reject arguments that “PJM-Classic” should be considered a separate relevant geographic market within PJM Pre-2004. We note that the PJM MMU report does not consider PJM-Classic as a separate market, and no one has shown that there are frequent binding transmission constraints that isolate PJM-Classic from the rest of PJM Pre-2004.

\(^8^8\) Application at 19.
124. We also reject arguments that PJM-West should be considered a separate geographic market. The critical issue in defining geographic markets is identifying the sellers who can physically and economically compete in the market. Given that the binding transmission constraints within PJM are predominantly west-to-east, it is reasonable to model PJM-East as a separate market within PJM, but not necessary to model PJM-West as a separate market because suppliers from all of PJM are able to sell into PJM-West.

125. Applicants have adequately addressed the protests concerning the fuel cost and wholesale market price assumptions in their analysis of energy markets. Dr. Hieronymus’ fuel cost and market price assumptions are consistent in that the assumed market price corresponds with the running costs of the units most likely to set the market-clearing price in the PJM energy markets for the given season-load conditions. We agree with Applicants that the fact that Dr. Hieronymus and Mr. Frame used different fuel cost and market price assumptions, but arrived at very similar results, indicates that the results are not sensitive to changes in fuel cost and market price assumptions. Moreover, the consistency of Dr. Hieronymus’ results across various assumed market prices shows that the results of the analysis are robust.\(^9\) In addition, the PJM MMU Study largely confirms the accuracy of Applicants’ results, finding similar pre-merger and post-merger concentration levels.

126. Applicants appropriately accounted for generation entry and exit in their analysis. They used publicly available data from PJM covering the 2006 test year and included retirements and new plant entries that are reasonably expected to occur in 2005 and 2006. In OG&E, we noted that we will consider foreseeable and reasonably certain changes in market conditions as part of the baseline scenario.\(^9\) Applicants have met that standard in their analysis.

127. Applicants and intervenors modeled various scenarios regarding who buys the divested assets. As noted by numerous protestors, as well as the PJM MMU Study, the effectiveness of Applicants’ proposed divestiture depends critically on the distribution of the buyers and their pre-existing presence as sellers in the PJM markets. Applicants initially addressed this issue by putting restrictions on the pool of eligible buyers and the

\(^9\) For example, using Economic Capacity in PJM-East, under assumed prices ranging from $55 to $80, the merger-related change in concentration ranges from 860 to 1,113 HHI and Applicants’ proposed divestiture of 4,500 MW of Economic Capacity returns the concentration to within 100 HHI of the pre-merger level. See Supplemental Hieronymus testimony, Exhibit J-28 p 1.

\(^9\) OG&E at P 32.
amount of the divested capacity that any one purchaser can acquire. However, many protesters argued that such restrictions could harm the competitive process and could even allow Applicants to gain a dominant position in PJM by having only smaller, weaker competitors.

128. The parties raise valid issues on both sides of this argument. We find that Applicants’ elimination of the restrictions on eligible buyers addresses protesters’ concerns about harming the competitive process by freezing out some of the possible or likely purchasers of the assets. However, we need to be sure that, at the conclusion of the divestiture, competition has been restored to its pre-merger level, for the merger to be consistent with the public interest. Therefore, in addition to our section 203 review of the individual divestiture transactions, at the end of the divestiture process Applicants must make a compliance filing in this docket and we will review the results to be sure that concentration in the affected markets is close to pre-merger levels. If the analysis shows that the merger’s harm to competition has not been sufficiently mitigated, we will require additional mitigation at that time. We will direct Applicants to make a compliance filing within 30 days of the closing of the final divestiture, with an Appendix A analysis showing the post-merger-and-divestiture market concentration levels for economic capacity in all relevant markets.

129. We are not persuaded by arguments that Applicants should have used an economic (i.e. least cost) allocation rather than a pro rata allocation of scarce transmission transfer capability in their analysis. We have accepted the pro rata allocation methodology in numerous merger cases, and believe it reasonably models suppliers’ ability to compete in a given destination market. Moreover, in Order No. 642, we stated:

A variety of allocation methods are possible, and the Commission has acknowledged that certain methods provide more accurate and reasonable results than others (i.e., pro-rata as opposed to least-cost). Applicants must describe and support the method used and show the resulting transfer capability allocation.\textsuperscript{91}

Here, Applicants have described and supported their transmission allocation methodology.\textsuperscript{92}

\textsuperscript{91} Order No. 642 at 31,894.

\textsuperscript{92} See Application Exhibit J-4 at p. 9.
130. Protestors raise a number of issues regarding Applicants’ Available Economic Capacity analysis. We agree with protestors and Applicants that in analyzing wholesale markets in retail choice states such as New Jersey and Pennsylvania, the native load deduction for the Available Economic Capacity calculation is difficult to assess. We have stated, in a number of contexts that as states move toward retail competition, native load obligations may change so that it is part of a broader set of contractual obligations, and we encourage applicants to test the sensitivity of the Available Economic Capacity results to changes in the native load assumptions. Here, Applicants have analyzed Available Economic Capacity under two different assumptions of the native load obligation and reported similar results: moderately concentrated markets with screen failures under most season/load conditions. Most importantly, in all time periods, the divestiture proposed to address the screen failures identified in the Economic Capacity analysis more than offsets the increase in concentration shown in the Available Economic Capacity analysis. We conclude that Applicants have shown that the merger, as mitigated, will not harm competition when Available Economic Capacity is used to measure suppliers’ ability to compete in those markets.

131. We are not convinced by arguments that Applicants should have analyzed the merger’s effect on their ability and incentive to harm competition by engaging in strategic bidding (which is a form of unilateral market power). The Commission’s analysis focuses on a merger’s effect on competitive conditions in the market. That is, we look at the merger’s effect on the concentration of the relevant markets, as measured by the HHI. Protestors argue that the HHI solely looks for the possibility of the coordinated exercise of market power and misses the possibility of the unilateral exercise of market power. They say that Applicants have not shown that the merger will not increase the likelihood of the merged firm exercising unilateral market power. We reject this argument for two reasons. First, the Merger Guidelines recognize that the HHI does, in fact, convey information about the likelihood of the unilateral exercise of market power. Second, in order to address the screen failures in various season/load conditions, Applicants have proposed divesting units with a range of operational and cost characteristics, including the types of units that protestors argue could be used to engage in strategic bidding or withholding in order to exercise unilateral market power.

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93 See Order No. 642 at 31,888.

94 Section 2.0 of the Merger Guidelines.
Furthermore, such strategic bidding or withholding could qualify as market manipulation under the Market Behavioral Rule #2\(^95\) and result in, among other things, revocation of market-based rate authority.

132. Protestors argue that Applicants have erroneously interpreted the Commission’s HHI screen as an absolute standard for merger authorization and, thus have offered mitigation that is focused solely on passing the screen, rather than on mitigating the merger-related harm to competition. We agree with protestors that the mitigation needs to preserve competition, not necessarily to restore the HHIs to avoid screen violations. There are a number of ways to mitigate increases in market power (e.g. generation divestiture, transmission expansion, or behavioral measures such as must-offer requirements), and we have imposed various forms of market power mitigation depending on the circumstances. Applicants’ proposal to divest sufficient capacity to reduce market concentration to within the screening tolerance for increases from the pre-merger concentration level is one reasonable way to mitigate the merger-related harm to competition.\(^96\) As stated above, the HHI conveys information about the likelihood of both the coordinated and unilateral exercise of market power. By restoring the HHI to near pre-merger levels, Applicants will restore competition to the pre-merger level, and meet their burden to show that the merger, as mitigated, will not harm competition in wholesale energy markets.

**B. Adequacy of Applicants’ Proposed Mitigation**

133. We are not convinced by FirstEnergy’s arguments that Applicants’ proposed divestiture does not sufficiently mitigate the merger-related increase in market power. In both studies, FirstEnergy’s witness, Ms. Frayer, understated the amount of the proposed mitigation in various seasons because she assumed a lower price in the mitigation scenario than in the post-merger-without-mitigation scenario, thus not giving credit for some of the units being divested. In short, divested units that were “economic” were incorrectly considered “uneconomic” by Ms. Frayer.

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\(^95\) Market Behavior Rules, 105 FERC ¶ 61,218 (2003) *Order on Reh’g*, 107 FERC ¶ 61,175 (2004) Rule # 2.E “bidding the output of or misrepresenting the operational capabilities of generation facilities in a manner which raises market prices by withholding available supply from the market.”

\(^96\) We note that Applicants’ analysis of the post-merger-and-mitigation market concentration shows one season/load condition for the PJM-East energy market where the change HHI is large enough to fail the Competitive Analysis Screen. As we have said in other merger cases, we do not find that borderline, non-systematic screen failures necessarily indicate harm to competition.
134. Protestors raise numerous issues regarding the effectiveness of Applicants’ proposed virtual divestiture of 2,600 MW of energy from nuclear capacity. In particular, many protestors argue that the Commission should only accept actual, physical divestiture as effective mitigation. However, as stated above, there are a number of possible effective market power mitigation tools, and we have recognized that different options can be reasonable for a given set of circumstances. We have recognized that operational control of generation resources is a key element of market power analysis and mitigation. Here, the virtual divestiture effectively transfers control of the output of 2,600 MW of nuclear capacity from the merged firm to the purchasers. That is, the merged firm cannot withhold the energy from the market and the buyer of the firm rights, not the seller, determines where and to whom the energy is ultimately sold. Applicants have committed to sell all of the energy that is offered, regardless of the price of the bids, and that an independent auction monitor will oversee Applicants’ compliance with that commitment. Moreover, the liquidated damages provisions in the contracts, reduce the merged firm’s incentive to withhold output to drive up wholesale energy prices because it would be contractually obligated to pay the cost of any price increase. In effect, the virtual divestiture is a must-offer provision that removes the ability to withhold output, along with a contractual provision that reduces the incentive to withhold output in order to affect market outcomes. As we have said in numerous contexts, we are concerned about a merger’s effect on the merged firm’s ability and incentive to harm competition.

135. Protestors also object to the virtual divestiture on the grounds that it will be difficult to monitor. For example, AAI notes that the antitrust agencies prefer physical divestiture because it removes the need for ongoing monitoring. We recognize that concern, but find two critical factors supporting virtual divestiture as a reasonable alternative to physical divestiture. First, as we have stated in a number of cases, the operational characteristics of, and regulatory scrutiny over, nuclear units virtually eliminate the possibility of withholding output to drive up prices. Second, Applicants have committed to establish an independent monitor to oversee the auction itself and Applicants’ compliance with the contracts, and Applicants will establish a public compliance website that will show how

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97 See, e.g., Order No. 642 at n. 39.

98 See, e.g., Order No. 642 at 94.

they are complying with the virtual divestiture and other mitigation requirements. We rely on those commitments in our finding that the virtual divestiture effectively mitigates the merger-related harm to competition. We will direct Applicants to make a compliance filing within 30 days of this order, detailing the process for the selection of the independent monitor.

136. We reject arguments that Applicants may have market power in the three-year and 15-year contract markets and that they may retain control of the contracts through the New Jersey Basic Generation Service auction. First, the Commission has determined that long-term capacity markets, absent specified entry barriers, are inherently competitive.¹⁰⁰ No protestor has raised compelling evidence that there are significant entry barriers in the PJM markets. Second, if Applicants attempted to withhold from the three-year contract market by selling only the 15-year contracts, as hypothesized by Ameren, the purchasers of the 15-year contracts would have an incentive to sell three-year contracts in response to any price increase. Regarding the PHI Companies’ argument about the New Jersey Basic Generation Service auction, Applicants have designed the three-year baseload energy auctions to support sales into the Basic Generation Service auction, but the buyers of the three-year baseload energy products will control the energy and can therefore resell them into the Basic Generation Service auction, or in some other manner. The fact that the buyers of the three-year baseload energy products may be likely to resell the energy into the New Jersey Basic Generation Service auction does not imply that the Applicants will regain control of the energy.

137. We reject FirstEnergy’s assertion that Applicants will receive the same price for the virtually divested energy as they would have in the absence of mitigation. First, as argued by Applicants, under the virtual divestiture plan, Applicants will receive the price determined in the auction for the three-year life of each contract, whereas if they retained control of the output of the nuclear units, they would be able to benefit from any market price increases during the same three-year period. Second, by giving up control of

6,600 MW of through the divestiture and virtual divestiture, Applicants have adequately mitigated the merger-related increase in market power. Therefore, they would not be able to raise the price of energy by other means, as the previous contracts expire, in order to raise the price they receive for the three-year contracts.

138. Protestors have argued that, the proposed energy swaps could harm competition in other geographic markets. Any such energy swaps will require section 203 authorization, and we will review the effect on competition in those proceedings. We note that swaps with suppliers in markets adjacent to PJM, such as MISO or the New York ISO, might not warrant a MW-for-MW reduction in the mitigation amount because Applicants would get control of capacity that could sell into PJM, subject to transmission constraints. In such cases, the MW reduction in Applicants’ mitigation amount would be reduced by the merged firm’s pro rata share of the import capability into PJM.

139. Likewise, we reject arguments regarding this merger’s possible effect on future mergers. Future mergers will require section 203 authorizations, and we will review the effect on competition in those proceedings. We note, without prejudice to any future proceedings, that Applicants’ divestiture plan will restore the concentration level in the relevant markets to within 100 HHI of the pre-merger level, so there will be little effect on future mergers.

140. The PHI Companies say that the three year baseload auction energy sales might not continue over the proposed 15-year period. In response, Applicants commit that the entire Baseload Mitigation Amount of nuclear virtual divestiture (2600 MW) will remain in place after 15 years, subject to a reduction in the mitigation amount if the Applicant’s PJM East nuclear capacity is decommissioned, derated, or sold or there is construction of new transmission transfer capability into PJM East. Therefore, Applicants have adequately addressed the PHI Companies’ concerns regarding the duration of the baseload auction energy sales.

141. A number of protestors argue that the Merger Policy Statement requires Applicants to identify the specific units that will be divested. In response, Applicants argue that while they cannot now identify the exact units, they do identify the location and the types of generation to be divested and the pool of generators eligible to buy. In addition, the PJM MMU states that without knowing the exact units and the buyers of those units, it could not “make a meaningful assessment of the effectiveness of the proposed divestiture,” and “a supplemental analysis must be performed once a definitive declaration of the divested assets has been developed.”

101 PJM MMU study at 2
Statement does state that applicants must identify the specific units to be divested, \(^{102}\) in this instance, we find Applicants’ proposal sufficient because the divestiture can adequately mitigate the merger-related harm to competition; moreover, once the specific units have been identified, we will be able to ensure that they are appropriate units to make divestiture effective through the subsequent compliance filing discussed above. Finally, establishing a pool of generation eligible for divestiture, rather than specifying exact units, addresses protestors’ “reverse cherry picking” argument that Exelon will divest its least valuable units, rather than creating viable competitors by divesting the efficient units. Establishing a pool of generation eligible for divestiture allows the potential buyers of the plants to bid on the ones that they most highly value.

142. We note that, because of the way the PJM MMU did its analysis (using unit-specific historical energy sales and calculating HHIs for units that can relieve internal PJM constraints), it did need to know the exact plants that are going to be divested in order to assess the effectiveness of the proposed divestiture. However, under the Commission’s Appendix A analysis, we need to know the general location (i.e. control area or sub-region of an RTO) and cost characteristics of the generators being divested – not the actual units - in order to calculate the post-merger-and-divestiture HHIs. Applicants have provided that information and shown that, based on reasonable assumptions about the buyers of the assets, the post-merger-and-mitigation HHIs are sufficiently close to the pre-merger HHIs to mitigate the merger-related harm to competition. Moreover, Applicants have committed to provide an Appendix A analysis of the merger’s effect on competition, based on the actual acquirers of the actual divested assets, once they are known. We rely on that commitment in making our finding that the divestiture adequately mitigates any merger-related harm to competition in the relevant energy markets. If the analysis shows that the merger’s harm to competition has not been sufficiently mitigated, we will require additional mitigation at that time, pursuant to our authority under FPA.

143. We find that Applicants’ proposed MW-for-MW reduction of the amount of the baseload energy mitigation is reasonable. As stated earlier in this order, there are a number of reasonable market power remedies, including divesture and transmission expansion and we have relied on those remedies based on the circumstances before us. We agree with Applicants that offsets to the baseload mitigation amount for increases in transmission transfer capability into PJM East are reasonable because increasing transfer capability into PJM-East would enable competitive suppliers to defeat attempts by generators in PJM East to drive up prices by withholding output. In fact, in OG&E, we found that a transmission expansion was a reasonable form of mitigation for the increase

\(^{102}\) We note that the Merger Policy Statement is not binding as a statute or regulation.
in market power associated with OG&E’s acquisition of a rival generator. Applicants have also made a convincing argument that a decrease in their nuclear capacity, whether through divestiture, de-rating, or unit retirement, would mitigate market power, because the incentive to withhold output is an increasing function of the amount of baseload capacity from which the merged firm could profit due to higher energy prices. Therefore, by reducing the amount of baseload capacity they control, they reduce their incentive to withhold marginal capacity in order to raise the market price.

144. We find that the amount of interim mitigation, along with Applicants’ variable cost bid caps for the mid-merit and peaking units, mitigates the merger-related harm to competition in the relevant energy markets. First, Applicants will offer the same amount of capacity in their interim mitigation (4,000 MW of fossil and 2,600 MW of nuclear) as in their proposed physical and virtual divestiture, which, as we explained above, adequately mitigates the merger-related harm to competition. Second, the commitment to bid the fossil units at variable cost eliminates the ability to harm competition by strategic bidding or economic withholding. In addition, we find that the Cassidy Testimony describing the amount of the dispatch rights; the rights afforded the purchasers of the capacity; the terms of the master agreement for the sales; the price of the energy and capacity; the timing and duration of the interim sales; and any associated rollover provisions, adequately describes the proposal. We rely on Applicants’ commitment to establish a public compliance web site that will show how they are complying with the virtual divestiture and all other mitigation requirements, including the interim mitigation plan, and require that the interim mitigation be in place upon consummation of the merger.

145. We reject arguments that we should address in this proceeding whether Applicants will pass the Commission’s market-based rates screen. Any issues regarding Applicants’ generation market dominance will be addressed in the pending proceeding on Exelon’s triennial review filing, and in future similar proceedings.

146. NiSource’s concerns about loop flows are related to ComEd’s participation in the PJM RTO and power flows between the Midwest ISO and PJM, not to the merger. Therefore we will address NiSource’s issues regarding loop flows in the proceeding under Docket No. EL05-103.

\footnote{OG&E at P 32.}
147. We agree with FirstEnergy’s argument that transmission expansion that is required by the PJM Regional Transmission Expansion Plan should not be considered market power mitigation. As we stated in OG&E, changes in market conditions that are “foreseeable and reasonably certain to occur” are not mitigation. Transmission upgrades, depending on where they fall in the PJM Regional Transmission Planning Process queue, can be foreseeable and reasonably certain to occur, and thus might not be considered mitigation. However, although we will accept Applicants’ transmission commitments, we are not relying on them in our finding that Applicants’ proposed mitigation adequately addresses the merger-related harm to competition. Rather we are relying on Applicants proposed sale of 6,600 MW of capacity to mitigate the merger-related harm to competition. As stated above, we will allow offsets to the baseload mitigation amount specifically for transmission expansions that increase import capability into PJM-East. At this time, Applicants have not proposed any new projects that would expand import capability into PJM-East. In order to grant an offset of the baseload mitigation amount, we will require Applicants to make a showing that any transmission upgrades would increase transfer capability into PJM-East, and that they were not foreseeable and reasonably certain as of June 2005. H-P Energy argues that Applicants’ commitment of $25 million towards transmission expansion projects may supplant transmission projects being built by merchant transmission companies. Applicants have addressed that concern, in part, by committing not to attempt to supplant any of the three projects identified by H-P Energy. In addition, we note that the PJM Regional Transmission Expansion Plan process identifies numerous transmission projects that could be undertaken by merchant transmission providers as well as other transmission providers and generators looking for interconnection. There are considerably more projects identified than undertaken in a given year. Therefore, we accept Applicants’ commitment to fund $25 million of transmission expansion projects and their commitment to avoid supplanting any of the H-P Energy identified projects. To avoid supplanting any other bidder seeking to fund any other project on PJM’s list of Economic Projects over the next five years, Applicants are required to bid only on those projects identified but not undertaken by any other entity. Additionally, we will require that Applicants follow all other procedures under the PJM Regional Transmission Expansion Plan for any transmission expansion projects.

148. Regarding FirstEnergy’s argument that Applicants have not demonstrated that their proposed internal corporate restructuring is consistent with the public interest, we note that, absent concerns about transfers of generation assets from unregulated merchant generating companies to regulated franchised utilities we expressed in Cinergy105 and

104 Id.

Ameren\textsuperscript{106}, the Commission has held that internal reorganizations will not result in harm to competition.\textsuperscript{107} Here, Applicants have committed that there will be no transfers of generation assets from unregulated merchant generating companies to regulated franchised utilities. We rely on that commitment in finding that that internal corporate restructuring will not result in any harm to competition in any relevant market. In addition, as discussed \textit{infra}, Applicants have committed to hold wholesale customers harmless from any merger-related costs so the internal reorganization will not adversely affect wholesale rates. Moreover, the internal restructuring will not adversely affect this Commission’s or any state commission’s ability to regulate the merged company. Therefore, we find that Applicants have shown that their proposed internal corporate restructuring is consistent with the public interest.

C. \textbf{Capacity Markets}

1. \textbf{Applicants’ Analysis}

149. Dr. Hieronymus also analyzed the effect of the merger on capacity markets in PJM-East and Expanded PJM. For PJM-East, he assumed the same 7,300 MW import capability as in his analysis of economic capacity. He reports that Exelon’s and PSE\&G’s pre-merger shares of capacity in PJM-East are 18 and 25 percent respectively and that the merger would increase market concentration from 1,282 to 2,196 HHI, well above the Commission’s screening threshold for highly concentrated markets. For Expanded PJM, he assumed the same 7,500 MW import capability as in his analysis of economic capacity. He reports that Exelon’s and PSE\&G’s pre-merger shares of capacity in Expanded PJM are 15 and 8 percent respectively and that the merger would increase market concentration from 799 to 1,044 HHI, above the Commission’s screening threshold for moderately concentrated markets. He states that Applicants need to divest 5,300 MW of capacity in PJM-East to eliminate the screen failures and restore market competition to the pre-merger level.\textsuperscript{108}

\textsuperscript{106} \textit{Ameren Energy} at 61,142.

\textsuperscript{107} \textit{See} Order No. 642 at 31,902.

\textsuperscript{108} Dr. Hieronymus finds that because PJM East is located within Expanded PJM, the capacity divestiture in PJM East would be effective mitigation for Expanded PJM and sufficiently reduce market concentration.
4. **Commission Determination**

217. We find that the merger will not adversely affect Commission or state regulation. We rely on Applicant’s commitment to follow the Commission’s Ohio Power policy in finding that the merger will not adversely affect Commission regulation. Applicants have shown that the transaction will not harm any state’s ability to regulate any of the merging parties. The merger is subject to review by the NJBPU, who can therefore protect its jurisdictional interests. We note that the PaPUC has intervened in the proceeding before the Commission, but has not requested that the Commission address any issues regarding the effect of the merger on its regulatory authority. Furthermore, the PaPUC, the Illinois Commerce Commission, and the NJBPU will retain regulatory authority over the merged company. We note that none of the affected state commissions have requested that the Commission address the effect of the merger on state regulation.

The Commission orders:

(A) Applicants’ proposed merger and internal restructuring is hereby authorized, subject to Commission acceptance of the Applicant’s compliance filings, as discussed in the body of this order.

(B) The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of costs, or any other matter whatsoever now pending or which may come before the Commission.

(C) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted.

(D) The Commission retains authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate.

(E) Applicants shall make any appropriate filings under section 205(a) of the FPA, as necessary, to implement the proposed Transaction.

(F) Applicants must submit their proposed final accounting within six months of the consummation of the merger. The accounting submission should provide all merger-related accounting entries made to the books and records of PSE&G, along with appropriate narrative explanations describing the basis for the entries.

(G) Applicants shall make a compliance filing to the Commission within 30 days of the completion of their divestiture, providing an Appendix A analysis of the merger’s effect on competition in energy and capacity markets, given actual plants and
assets divested and the actual acquirers of the divested assets. If the analysis shows that
the merger’s harm to competition has not been sufficiently mitigated, Applicants must
propose additional mitigation at that time.

(H) Applicants shall make a compliance filing to the Commission within
30 days of this order showing that they have established an independent monitor to
oversee the baseload energy auction and Applicants’ compliance with the terms of the
energy contracts; and that they have established a public compliance website the showing
how they are complying with the virtual divestiture and other mitigation requirements,
including the interim mitigation.

(I) Applicants shall notify the Commission within 10 days of the date that the
merger has been consummated.

By the Commission.

(SEAL)

Magalie R. Salas,
Secretary.
IN THE MATTER OF THE JOINT PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION FOR APPROVAL OF A CHANGE IN CONTROL OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY, AND RELATED AUTHORIZATIONS

BPU DOCKET NO. EM05020106; OAL DOCKET NO. PUC1874-05

New Jersey Board of Public Utilities

2005 N.J. PUC LEXIS 104

November 9, 2005, Dated

PANEL: [*1] JEANNE M. FOX, PRESIDENT; FREDERICK F. BUTLER, COMMISSIONER; CONNIE O. HUGHES, COMMISSIONER; JACK ALTER, COMMISSIONER

OPINION: ENERGY

ORDER ON STANDARD OF REVIEW

BY THE BOARD:

The Board of Public Utilities ("Board"), by this Order, addresses the issue of the standard of review to be applied in rendering its determination on the requests for Board approvals, authorizations and other relief sought by the Verified Joint Petition in the above-referenced matter. As discussed more fully below, the Board issues this Order after affording the parties an opportunity to submit comments and reply comments on the standard of review which the Board should apply in considering the Verified Joint Petition in the above-captioned matter, and after careful consideration of all submissions made in this regard.

BACKGROUND/PROCEDURAL HISTORY

By Verified Joint Petition filed with the Board on February 4, 2005, and thereafter supplemented by letters dated February 7, 9, and 28, 2005, Public Service Electric and Gas Company ("PSE&G") and Exelon Corporation ("Exelon") (collectively "Joint Petitioners"), request that the Board issue an Order: 1) approving the acquisition of control of PSE&G as contemplated [*2] by an Agreement and Plan of Merger between Exelon and Public Service Enterprise Group Incorporated ("PSEG"), dated as of December 20, 2004 (Exhibit JP-1C); 2) authorizing Exelon's subsidiary Exelon Energy Delivery Company, LLC ("Exelon Energy Delivery") to acquire control of PSE&G, pursuant to N.J.S.A. 48:2-51.1 and N.J.S.A. 48:3-10; 3) authorizing the recording of a regulatory asset to offset the purchase accounting adjustments resulting in an increase in the balance sheet liabilities for PSE&G's pension and other post retirement benefits plans; 4) approving a General Services Agreement and Mutual Services Agreement (Exhibits JP-1E and 1F) pursuant to N.J.S.A. 48:3-7.1; and 5) approving PSE&G's execution of and action in accordance with the Exelon Utility
Money Pool Agreement (Exhibit JP-1G) pursuant to N.J.S.A. 48:3-7.2. The Verified Joint Petition also requests that the Board's Order include a determination that the Board has sufficient regulatory authority, resources and access to the books and records [*3] of PSE&G and any relevant associate, affiliate or subsidiary company to exercise its duties, and that, post-merger, participation by any affiliate or associate company of PSE&G that is an exempt wholesale generator ("EWG") in the Basic Generation Service ("BGS") process will benefit consumers, does not violate any State law, would not provide the EWG any unfair competitive advantage by virtue of its affiliation or association with PSE&G, and is in the public interest. The Verified Joint Petition also requests that the Board submit a letter to the Securities and Exchange Commission ("SEC") in the form attached to the Verified Joint Petition as Exhibit JP-1H, which proposes that, with regard to a request by Exelon to increase its SEC authorization under the Public Utility Holding Company Act of 1935 ("PUHCA") for its total investment in EWGs and foreign utility companies ("FUCOs") from the currently authorized aggregate level of $4 billion to a post-merger aggregate level of $7 billion, the Board inform the SEC that the Board "has the authority and resources to protect the ratepayers of PSE&G [*4] and the ratepayers of PSE&G." The Verified Joint Petition is verified on behalf of Exelon by Elizabeth Moler, Executive Vice President of Exelon, and on behalf of PSE&G by R. Edwin Selover, Senior Vice President and General Counsel of PSE&G, and is supported by direct testimony in Exhibits JP-2 through JP-7 thereto.

n1 The testimony filed with the Verified Joint Petition was later supplemented and revised in certain respects, such that, as of the Board's June 22, 2005 agenda meeting, the following constituted the prefilled testimony: Exhibit JP-2, Direct Testimony of John W. Rowe, Exelon's Chairman, President and Chief Executive Officer; Exhibit JP-3, Direct Testimony of Ralph Izzo, PSE&G's President and Chief Operating Officer; Exhibit JP-4, Direct Testimony of J. Barry Mitchell, Exelon's Senior Vice President, Treasurer and Business Unit Chief Financial Officer; Exhibit JP-5, Direct Testimony of William Arndt, Exelon's Senior Vice President, Business Operations; Exhibit JP-6, Direct Testimony of Rodney Frame, Managing Principal of Analysis Group, Inc.; and Exhibit JP-7, Direct Testimony of Pamela B. Strobel, Exelon's Executive Vice President and Chief Administrative Officer, and President of Exelon Business Services Company. The Board notes that thereafter, by letters dated August 3, 2005 and September 28, 2005 to Administrative Law Judge Richard McGill, the Joint Petitioners submitted Exhibit JP-7A, Direct Testimony of Ruth Ann M. Gillis, Senior Vice President of Exelon and President of Exelon Service Company, adopting the testimony of Pamela B. Strobel, who will be retiring prior to the hearings to be held in this matter. The Board also notes that by letter dated August 15, 2005 to Board Secretary Kristi Izzo, the Joint Petitioners submitted the following testimonies: Exhibit JP-6, Additional Direct Testimony of Rodney Frame; Exhibit JP-8, Direct Testimony of E. James Ferland, PSEG's Chairman, Chief Executive Officer and President, and Thomas M. O'Flynn, PSEG's Executive Vice President and Chief Financial Officer; Exhibit JP-9, Direct Testimony of Frank Cassidy, President and Chief Operating Officer of PSEG Power, LLC; and Exhibit JP-10, Direct Testimony of Kenneth W. Cornew, Senior Vice President of Power Transactions for Exelon Generation Company, LLC.

[*5] The Verified Joint Petition and the direct testimony describe the parties to the proposed acquisition of control and related agreements. PSE&G, a corporation organized and existing under the laws of the State of New Jersey and a wholly-owned subsidiary of PSEG, is engaged principally in the transmission and distribution of electric energy and gas service in New Jersey. PSE&G is both an electric public utility and a gas public utility subject to regulation by the Board. PSE&G has approximately 2.0 million electric customers and 1.6 million gas customers in a service area of approximately 2,600 square miles running diagonally across New Jersey from Bergen County in the northeast to an area below the City of Camden in the southwest. The greater portion of this area is served with both electricity and gas, but some parts are served with electricity only and other parts with gas only. Verified Joint Petition at P 1; Exhibit JP-6 at 12. PSE&G also provides BGS and basic gas supply service ("BGSS") to its customers who, respectively, have not
chosen an alternative electric power supplier or alternative gas supplier. PSE&G secures the wholesale requirements for its supply of BGS through a Board-approved auction process. Exhibit JP-6 at 12. PSE&G has turned over the operational control of its electric transmission system to PJM Interconnection, LLC ("PJM"), the Regional Transmission Organization ("RTO") approved by the Federal Energy Regulatory Commission ("FERC") for a centrally dispatched control area comprising all or parts of several states, including New Jersey, and the District of Columbia. Verified Joint Petition at P 1.

PSEG, the parent of PSE&G, also is a corporation organized and existing under the laws of the State of New Jersey and presently is an exempt public utility holding company under PUHCA. Id. at P 2. The common stock of PSEG is publicly traded and is listed on the New York Stock Exchange. Ibid. In addition to PSE&G, PSEG has three other principal direct wholly-owned subsidiaries: PSEG Power LLC ("PSEG Power"), described by the Verified Joint Petition as a multi-regional, wholesale energy supply company that includes generating asset operations, as well as wholesale energy, fuel supply, energy trading and marketing and risk management functions; PSEG Energy Holdings LLC ("PSEG Energy Holdings"), described by the Verified Joint Petition as having pursued investment opportunities in the global energy markets; and PSEG Services Corporation ("PSEG Services"), described by the Verified Joint Petition as providing corporate support, managerial and administrative services to PSEG and its subsidiaries. Verified Joint Petition at P 2. PSEG Power, in turn, is described by Exhibit JP-6 as having three principal subsidiaries: PSEG Nuclear LLC ("PSEG Nuclear"), PSEG Fossil LLC ("PSEG Fossil") and PSEG Energy Resources & Trade LLC ("PSEG ER&T"). PSEG Nuclear has an ownership interest in five nuclear generating units and operates three of them: the Salem Nuclear Generating Station, Units 1 and 2, each of which is owned 57.41% by PSEG Nuclear and 42.59% by Exelon Generation Company LLC ("Exelon Generation"), and the Hope Creek Nuclear Generating Station, which it owns 100%, while Peach Bottom Atomic Power Station Units 2 and 3, each of which is 50% owned by PSEG Nuclear, are operated by Exelon Generation. Exelon Corporation Form S-4 (Registration Statement under the Securities Act of 1933), Amendment No. 3, filed with Securities and Exchange Commission on May 27, 2005, Registration No. 333-122704 ("Form S-4") at 38.

Exelon is a corporation organized and existing under the laws of the Commonwealth of Pennsylvania and is a registered holding company under PUHCA. Verified Joint Petition at P 3. The common stock of Exelon is publicly traded and is listed on the New York Stock Exchange. Ibid. According to the Verified Joint Petition, Exelon, through its subsidiaries, operates in three business segments, which have been denominated Energy Delivery, Generation and Enterprises, and, through a subsidiary service company, provides business services to the consolidated group. Ibid.

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n2 Form S-4 is referenced in the Verified Joint Petition at P 43.

[*9] As described by the Verified Joint Petition, Exelon's energy delivery business is conducted through its second-tier subsidiaries PECO Energy Company ("PECO") and Commonwealth Edison Company ("ComEd"), whose immediate parent is Exelon Energy Delivery. Verified Joint Petition at P 4. PECO is engaged in the business of supplying, transmitting and distributing electricity and natural gas and furnishes retail electric and natural gas service in several counties in Pennsylvania. Ibid. PECO's retail service territory has an area of approximately 2,100 square miles and an estimated population of 3.8 million. PECO provides electric delivery service in an area of approximately 2,000 square miles, with a population of approximately 3.7 million, including 1.5 million in the City of Philadelphia. Natural gas
service is supplied in an area of approximately 1,900 square miles in southeastern Pennsylvania adjacent to the City of Philadelphia, with a population of approximately 2.3 million. PECO delivers electricity to approximately 1.5 million customers and natural gas to approximately 460,000 customers. Form S-4 at 37. ComEd is engaged in the business of supplying, transmitting and distributing electricity in Northern Illinois and, through a wholly owned subsidiary, provides electric transmission service in portions of Indiana. Verified Joint Petition at P 4. ComEd's retail service territory has an area of approximately 11,300 square miles and an estimated population of 8 million, which includes the City of Chicago, an area of about 225 square miles with an estimated population of 3 million. ComEd has approximately 3.76 million customers. Form S-4 at 37. PECO and ComEd also have turned over operational control of their electric transmission systems to PJM. Verified Joint Petition at P 4.

The Verified Joint Petition further describes that Exelon's generation business consists of electric generating facilities that Exelon Generation owns or has under contract. Verified Joint Petition at P 5. These facilities have a net capacity of approximately 33,000 MW, of which approximately 21,000 MW is located in PJM. Of this amount, 7,180 MW is in PJM East, described by the Joint Petitioners as the area in PJM that is located, in an electrical sense, to the east of PJM's Eastern Interface. Exhibit JP-6 at 5, 14. Exelon has ownership interests in ten nuclear generating stations comprised of seventeen individual units, and its nuclear holdings include interests in the Salem and Peach Bottom stations, which are owned jointly with PSEG Nuclear. Id. at 14. Exelon's generation business also includes the wholesale energy marketing operations of Exelon Generation and the competitive retail sales business of Exelon Energy Company. Verified Joint Petition at P 5. In addition to Exelon's three business segments, Exelon Business Services Company ("Exelon BSC"), a first-tier subsidiary of Exelon, provides Exelon and its subsidiaries with advisory, professional, technical and other services. Id. at P 6.

The Verified Joint Petition also provides an overview of the proposed transaction at PP 7-13. Pursuant to the terms of the Merger Agreement attached to the Verified Joint Petition as Exhibit JP-1C, PSEG will merge into Exelon, thereby ending the separate corporate existence of PSEG. Each PSEG shareholder will be entitled to receive 1.225 shares of Exelon common stock for each PSEG share held and will be paid cash in lieu of any fractional share of Exelon stock the PSEG shareholder would otherwise be entitled to receive. As proposed, Exelon, which will be renamed Exelon Electric & Gas Corporation ("EE&G"), will be the surviving company, remain the ultimate corporate parent of PECO and ComEd and the other Exelon subsidiaries and become the ultimate corporate parent of PSE&G and the other surviving PSEG subsidiaries. Verified Joint Petition at P 7. Under the proposed transaction, ComEd, PECO and PSE&G will continue to be operating public utility companies. The Verified Joint Petition proposes that EE&G will remain headquartered in Chicago, with electric generation headquarters in Newark, New Jersey, and energy trading and nuclear divisions headquartered in southeastern Pennsylvania. The Verified Joint Petition also proposes that PSE&G will remain headquartered in Newark, with PECO and ComEd remaining headquartered in Philadelphia and Chicago, respectively. Id. at P 8.

The Verified Joint Petition also indicates that EE&G will assume all of PSE&G's outstanding indebtedness, that the indebtedness of PSE&G will not be assumed or guaranteed by EE&G and will remain the obligation of PSE&G and any of the guarantors of such indebtedness; and that the proposed merger will not change the terms or character of PSE&G or any Exelon subsidiary's outstanding preferred stock or other indebtedness, which will continue to be outstanding. Id. at PP 9 and 10.

The Verified Joint Petition further states that after the proposed merger, EE&G will increase the number of Directors on its Board of Directors to eighteen and will appoint six former PSEG Directors designated by the former PSEG Chief Executive Officer to fill six Directors' seats. Id. at P 11. Additionally, the Verified Joint Petition indicates that the following will hold offices after the merger: John W. Rowe, the current Chairman, Chief Executive Officer and President of Exelon, will serve as Chief Executive Officer and President of Exelon; E. James Ferland, the current Chairman, Chief Executive Officer and President of PSEG, will become the non-executive Chairman of the Exelon Board of Directors and upon his departure from the Board of Directors, John W. Rowe will assume the Chairmanship; and Ralph Izzo, PSE&G's current President and Chief Operating Officer will remain in that position. Id. at P 12.
In addition to the changes resulting from the Merger Agreement, the Joint Petitioners propose to revise their corporate structure so that, among other changes, PSE&G will [*14] become a direct subsidiary of Exelon Energy Delivery, which, as noted above, is, in turn, a direct subsidiary of Exelon and the parent of ComEd and PECO, with PSE&G's current subsidiaries remaining intact. They also propose that PSEG Services will sell all of its assets to Exelon Business Services Company and remain as a non-energy entity, and that post-merger, Exelon Business Services Company will be the sole service company of EE&G. Id. at P 13.

In a section of the Verified Joint Petition captioned "Benefits of the Merger," at P 14, the Joint Petitioners assert that the proposed merger "will create a company with substantial resources and capabilities that will serve over seven million retail electric customers and two million retail gas customers in three states" and that "by sharing resources and best practices, the proposed Merger is expected to enhance operations and strengthen the combined ability of Exelon's utility subsidiaries to provide cost-effective, safe and reliable service and will affirmatively promote the public interest in a number of substantial ways." These are enumerated as including: increased scale and scope; anticipated financial strength and flexibility; [*15] sharing of best practices; synergies; commitment to competition; impact on customers, employees, and suppliers; and impact on communities served. Verified Joint Petition at P 14(a)-(g).

The Verified Joint Petition also includes, among other sections, a section pertaining to PP 21-37 captioned "Regulatory Standards for Approval." In this section, the Verified Joint Petition asserts that "the Board has long established that the governing standard under N.J.S.A. 48:2-51.1 and N.J.S.A. 48:3-10 for its approval of the acquisition of control of a New Jersey public utility is that the proposed transaction will not adversely impact upon' the financial integrity of the New Jersey utility . . . and will result in no harm' or no adverse impact' on the four areas specified in N.J.S.A. 48:2-51.1," i.e., competition, the rates of ratepayers affected by the acquisition of control, the employees of the affected public utility, and the provision of safe and adequate utility service at just and reasonable rates. Verified Joint Petition at P 21 (citation [*16] omitted). The Verified Joint Petition claims that the petitioned-for change in control satisfies the no harm standard for reasons set forth in PP 22-37.

By letter dated February 18, 2005, the Board transmitted the Verified Joint Petition to the Office of Administrative Law ("OAL"), where it was assigned to Administrative Law Judge ("ALJ") Richard McGill. After the holding of a prehearing conference, ALJ McGill issued a Prehearing Order on April 5, 2005. Among other matters, the Prehearing Order set forth the nature of proceeding and issues to be resolved, but did not indicate that an issue to be addressed is the standard of review. In response to ALJ McGill's Prehearing Order, Board Staff submitted a letter dated April 15, 2005, in which it stated, among other things, that "as indicated at the prehearing conference, Staff anticipates that the standard of review may be at issue."

At its May 5, 2005 agenda meeting, the Board, noting that there had to date been no schedule established for disposition of this issue before the ALJ, determined to recall the standard of review issue from the OAL and established a schedule to afford an opportunity for parties to be heard on the standard [*17] of review issue through the submission of briefs prior to the Board ruling thereon. ALJ McGill and the Service List were notified by Secretary's letter dated May 5, 2005 of the Board's recall of the standard of review issue and that initial briefs by any party wishing to be heard on the standard of review should be submitted by May 26, 2005, with reply briefs by June 6, 2005.

At its June 22, 2005 agenda meeting, the Board considered the submissions of the parties, which are summarized below, and rendered its determination regarding the standard of review to be applied in reviewing the Verified Joint Petition in the within matter. This Order memorializes that decision.

INITIAL COMMENTS

Joint Petitioners
The Joint Petitioners argue that a no harm standard should be applied in the review of their Verified Joint Petition. They maintain that in the majority of mergers and acquisitions the Board has considered, including all recent electric utility transactions, a no harm standard has been used to conduct the evaluation required under N.J.S.A. 48:2-51.1. Joint Petitioners Initial Brief at 1-2. They assert that it would be inappropriate, before the development of any factual record, to depart from the no harm standard, which they claim has served the Board satisfactorily in many cases. Id. at 2. The Joint Petitioners further allege that any decision to depart from what they refer to as the settled no harm standard would create unnecessary confusion and would be arbitrary. Ibid. The Joint Petitioners assert that application of the no harm standard in prior cases reflects a practical balancing approach based on the totality of the evidence that the Board should continue to apply here. Id. at 3. They contend that application of the standard requiring no adverse impact on the criteria in N.J.S.A. 48:2-51.1, such as employees of the affected public utility, does not mean that the standard cannot be satisfied if the elimination of a single utility employee position is anticipated. Ibid.

The Joint Petitioners also argue that when the Board has applied a positive benefits standard, special circumstances were present, which they claim are not relevant here. Id. at 4. The Joint Petitioners also contend that even when the Board has used a positive benefits standard, it has followed virtually the same balancing test as applied in the no harm cases. Id. at 6. The Joint Petitioners further argue that there is not clear guidance as to how a positive benefits test would work under the circumstances of this case, which they argue does not involve operational or financial difficulties threatening to impair service. Hence, the Joint Petitioners argue that it is unclear what the aim of a positive benefits standard would be in the within matter. Ibid. They contend that without a factual record in place, it is difficult to see how the within matter should be distinguished from other electric company merger proceedings in which the Board applied a no harm standard. Ibid. The Joint Petitioners conclude by arguing that although they will show that there are positive benefits arising from this transaction, the imposition of a positive benefits standard in the within matter, in which they claim there is no evidence supporting the need for such a standard nor any direction as to how it would be applied, would be inconsistent with Board precedent and arbitrary. Id. at 6-7. They assert that the no harm standard will allow the Board to consider all impacts of the proposed transaction, including the positive benefits, and ensure the continued provision of safe and adequate service at just and reasonable rates. Id. at 6.

Ratepayer Advocate

The Division of the Ratepayer Advocate ("RPA" or "Ratepayer Advocate") asserts that the proper standard to be used in evaluating the merits of the transaction at issue herein is that of "positive benefit to the public interest." RPA Initial Brief at 1. The RPA notes that the positive benefits standard has its origins in merger or "takeover" cases affecting the internal structure of existing New Jersey utilities and that under this standard, also referred to as the "best interest of the public" or "of positive benefit to the public interest," the petitioners are required to demonstrate benefits that would accrue to ratepayers if a proposed transfer of control is approved. Id. at 5. The RPA asserts that the Board has applied the no adverse impact standard with regard to proposed acquisitions not significantly affecting the utility's internal structure and that recent merger cases indicate the Board's reluctance to adopt a universal standard of review. Id. at 6. The RPA notes that the Board has articulated a no adverse impact standard in certain recent merger cases but also notes that in the Board's Order in its most recent merger proceeding, Order of Approval, I/MO Petition of NUI Utilities, Inc. (d/b/a/ Elizabethtown Gas Company) and AGL Resources Inc. for Authority under N.J.S.A. 48:2-51.1 and N.J.S.A. 48:3-10 of a Change in Ownership and Control ("NUI"), Docket No. GM04070721 (November 17, 2004), the Board explicitly required the petitioners to demonstrate positive benefits as a condition for approval. Id. at 7. The RPA also argues that even prior to NUI, the Board had indicated a trend towards positive benefits as a condition precedent to merger approval, and cite in support thereof to Commissioner Butler's dissent in I/M/O the Joint Petition of FirstEnergy Corp. and Jersey Central Power & Light Co., d/b/a GPU Energy, for Approval of a Change in Ownership and Acquisition of Control of a New Jersey Public Utility and Other Relief ("FirstEnergy"), Docket No. EM00110870 (October 9, 2001), in which he explained that he was not convinced that approval of the proposed acquisition was in the public interest and in his view the proposed acquisition "provided no real benefit to the ratepayers." Id. at 7.

The RPA further asserts that regardless of the articulated standard of review, the Board has required that positive
benefits flow to customers as a prerequisite of merger approval. Ibid. The RPA contends that the Board should explicitly mandate a demonstration of positive benefits by the Joint Petitioners because of the Board's history of requiring utilities to implement positive benefits and what it refers to as the unique circumstances involved in the proposed integration of PSE&G into Exelon, which the RPA identifies as a sale to a foreign company of one of New Jersey's most prominent corporations with a statutory obligation to serve its customers and the acknowledged creation of significant market power in the PJM area most relevant to the BGS auction. Id. at 9-10. Noting that the purpose of the Electric Discount and Energy Competition Act ("EDECA"), N.J.S.A. 48:3-49 et seq., was to create a competitive retail market, the RPA submits that the merger [*23] "must actively encourage competition, not merely fail to destroy it completely." Id. at 10. It further argues that PSE&G's ratepayers, not only its shareholders, should benefit from resulting synergies of the $79 billion transaction. Ibid. In discussing the employee prong of N.J.S.A. 48:2-51.1, the RPA asserts that "the Board should review the Joint Petitioners' plans regarding Public Service's employees on a positive benefits standard; otherwise, many employees will surely be harmed." Id. at 11. The RPA also maintains that the Board should insist on improvements in safety and reliability, not merely avoidance of deterioration. Ibid. Noting that in their petition, the Joint Petitioners, themselves, offer a detailed explanation of how the proposed merger will potentially benefit the public interest, the RPA argues that this reflects an implicit understanding that utilities must show the positive benefits of any proposed merger. Id. at 12. The RPA urges the Board to require the Joint Petitioners to substantiate this representation by evaluating the Verified Joint Petition under a positive benefits standard of review. [*24] Ibid.

**Board Staff**

Board Staff urges the Board to apply the positive benefit standard to the Verified Joint Petition. Board Staff Initial Brief at 1. Board Staff notes that in applying the applicable law in its review of mergers, the Board's approach, necessarily reflecting the extremely fact-sensitive nature of the proceedings, has not been monolithic. Id. at 2. It further notes that as is being done in the within matter, the determination of the standard of review has been identified and litigated in each proceeding on a case-by-case basis, with arguments generally having centered on a no-harm standard and a positive benefits standard. Ibid. Board Staff points out that the Board recently found that, although generally it had relied upon the no harm standard in certain prior cases, it was appropriate with regard to the acquisition under consideration "to expand the scope of its review to capture expectations for improvements, e.g., some positive benefits, since [the utility] ETG enters the process with credit ratings below investment grade, restricted access to capital markets, very high interest rates on existing lines of credit, significant prepayment [*25] burdens under its gas procurement arrangements, and a serious need to reestablish the trust and confidence of ratepayers, bondholders and investors." Id. at 2, citing NUI at 6. Board Staff asserts that here, too, in keeping with its longstanding practice of ruling upon the appropriate standard of review on a case-by-case basis, the Board should determine the appropriate standard for this application. Id. at 2.

Board Staff states that the present petition is "of critical importance to the State of New Jersey." Ibid. As it explains: PSE&G is the largest utility in the State; its parent company, PSEG has three other subsidiaries, PSEG Power LLC, PSEG Energy Holdings LLC and PSEG Services Corporation; the petition envisions PSEG's merger into Exelon, which, in turn, by means of its subsidiaries, operates in business segments that it describes as energy delivery, generation and enterprise, in addition to provision of business services; and two of Exelon's energy delivery subsidiaries are PECO Energy Company, which provides energy to several counties in Pennsylvania and Commonwealth Edison Company, which provides electricity to northern Illinois, and through another subsidiary, [*26] electric transmission to portions of Indiana. Id. at 3. Board Staff further describes that the merger would result in the largest utility in the industry. Ibid., citing Stavros "The Man Who Would Be King; Exelon Chairman, President and CEO John W. Rowe, on the Proposed Merger That Would Create the Largest Utility in the United States," Public Utilities Fortnightly, May 2005, at 15 ("The Man Who Would Be King"). Board Staff asserts that the proposed merged utility would be the country's largest power generator and a leading national wholesale power marketer with a generation portfolio of about 52,000 MW of domestic capacity, including about 20,000 MW of nuclear generation, and that Exelon Nuclear operates seventeen nuclear reactors, the largest string in the country and the third largest in the world, with the merger proposing to add PSEG Power's three nuclear facilities. Id. at 3, citing "The Man Who Would be King";
New Jersey Citizen Action

New Jersey Citizen Action ("NJCA") urges the Board to use a positive benefits standard of review in this and all merger and acquisition petitions that come before the agency. NJCA Initial Brief at 2. NJCA contends that in the past, the Board has used a no harm standard in reviewing similar cases, but that the Board is not bound by statute to use such a standard in all cases. Ibid. NJCA argues that a positive benefits standard is particularly appropriate in this case because of "failed policies to lower rates in New Jersey, the failure of prior acquisitions of New Jersey's public utilities to produce long-term significant savings to ratepayers, recent labor strife within the utility sector and given the breadth and scope of the petition . . . and in particular its potential impact on competition." Id. at 2-3. To satisfy this standard, NJCA claims that the Joint Petitioners must establish that the proposed acquisition will positively impact each prong of the statutory criteria and that such benefits must be significant and sustainable. Id. at 3. NJCA further argues that if positive benefits are found, 100% of those net positive benefits should be passed on to ratepayers in the form of rate reductions. Ibid.

New Jersey Large Energy Users Coalition and Retail Energy Supply Association

The New Jersey Large Energy Users Coalition ("NJLEUC") and Retail Energy Supply Association ("RESA") urge the Board to adopt a "no harm with positive conditions attached" standard. NJLEUC and RESA Initial Brief at 2. NJLEUC and RESA note that while not dispositive herein, the Joint Petitioners will, in fact, have to satisfy a positive benefits standard of proof in the Pennsylvania proceeding because the applicable Pennsylvania statutes were interpreted by the Pennsylvania Supreme Court in York v. Pa. P.U.C., 449 Pa. 136, 295 A.2d 825, 828 (1972), to require those seeking approval of a utility merger to demonstrate that the merger would affirmatively promote the service, accommodation, convenience, or safety of the public in some substantial way." Id. at 4-5. NJLEUC and RESA urge that the positive benefits standard would be the more appropriate standard in New Jersey to govern merger transactions involving stock transfers and in particular, this stock transfer where Joint Petitioners propose the formation of the country's largest public utility. Id. at 5. They argue that the positive benefits standard would provide a measure of balance between the benefits conferred upon the utilities' officers and shareholders on the one hand, and its ratepayers, competitors and other stakeholders on the other; a balance that is decidedly absent thus far." Ibid.

NJLEUC and RESA indicate that they recognize that in the last four electric utility mergers, the Board determined to apply the no harm standard, but they argue that at the same time, the Board has retained the authority to adopt the standard of review it determines will best fit the circumstances of a particular case. Id. at 6. They further point to the recent NUI Order in which the Board determined that, notwithstanding its prior reliance on the no harm standard, in the particular circumstances therein, it was appropriate to expand the scope of review to include expectations regarding the positive benefits that the Joint Petitioners had represented would flow from the merger. Id. at 7. Thus, they argue that "this succession of Orders demonstrates the Board's authority to adopt the standard of review it determines will best fit the circumstances of a particular case." Ibid. NJLEUC and RESA further contend that even in those proceedings in which the Board has adopted a no harm standard, the Board has consistently conditioned its approval of merger transactions on the conferring of compensatory or positive benefits to the ratepayers and other stakeholders, to insure that rates, competition, employees and service quality will not be harmed by the merger. Id. at 7. Therefore, they urge the Board to adopt the same no harm with positive conditions attached standard herein. Ibid.
NJLEUC and RESA argue that the Board, on numerous occasions, has, notwithstanding its adoption of a no harm standard, indicated that it is not precluded from scrutinizing a merger's claimed benefits and that where, as here, Joint Petitioners tout purported benefits that will flow from a merger, the Board has considered the issue of the appropriate treatment of purported merger benefits to be properly before the Board and has examined whether, for example, such benefits have been properly derived and equitably shared with stakeholders. Ibid. NJLEUC and RESA maintain that in every merger proceeding, the Board has accorded lengthy treatment to synergy savings issues to determine whether ratepayers may be harmed by a plan of merger that reduces ratepayer investment in the utility without adequate compensation. Id. at 8-9. NJLEUC and RESA contend that the Board should accord the same type of treatment to synergy savings in this proceeding, in which they assert that PSE&G shareholders will receive a significant premium, so as to closely scrutinize the savings that will accrue [*32] from this multi-billion dollar merger. Id. at 9. NJLEUC and RESA also contend that, in addition to the treatment of synergy savings, the Board, in cases applying the no harm standard, has approved a wide array of merger conditions and stakeholder benefits, some of which they assert had little or no relationship with any of the four statutory criteria. Ibid.

In conclusion, NJLEUC and RESA urge the Board to adopt a no harm standard with positive conditions attached. They maintain that such a standard would be consistent with the standard adopted in past merger proceedings, would require the utility to meet its burden of demonstrating that the transaction would not harm competition, rates, employees and adequacy of utility service by reference to the record developed and through conditions assuring that all parties affected by the merger are not harmed thereby and derive some affirmative benefit therefrom. Id. at 12. They further contend that such a standard would be particularly appropriate in this proceeding, in which concerns regarding the merger's potential effect on market power and competition and attendant impact on rates to customers, and the potential diminution [*33] of regulatory control over the State's largest utility are particular [sic] vexing, while the purported benefits to stakeholders are far less clear.” Ibid. They reiterate their view that such a standard would provide a measure of balance between the benefits conferred upon shareholders and officers on the one hand, and ratepayers and competitors on the other, and would assure that the merger "makes sense" for all parties affected by it, and not "merely utility shareholders and certain favored individuals within the merged companies." Ibid.

Utility Workers Union of America, AFL-CIO and UWUA Local 601

Utility Workers Union of America, AFL-CIO ("UWUA") and UWUA Local 601 ("Local 601") urge the Board to adopt a standard that the acquisition (a) will not cause an adverse impact with respect to any of the listed, statutory criteria; and (b) will result in positive benefits for PSE&G customers. UWUA and Local 601 Initial Brief at 2. UWUA and Local 601 argue that a positive benefits standard is appropriate given the high quality of service provided by PSE&G and the risk that an acquisition by Exelon may harm PSE&G customers. Id. at 3. UWUA and Local 601 contend that [*34] such a standard should provide an extra measure of assurance that approval of the proposed transaction is in fact consistent with the public interest and that without a showing of positive benefits, there would be little reason for any PSE&G ratepayer to be enthusiastic about the proposed acquisition, or for the Board to risk the potential for acquisition related harms. Ibid. They argue that the proposed acquisition is virtually certain to harm PSE&G ratepayers and workers unless properly conditioned. Id. at 4. They claim that cost-cutting pressures created by the $ 2 billion acquisition premium being paid by Exelon to PSE&G shareholders could jeopardize PSE&G's long record of providing outstanding service at reasonable rates. Ibid. They allege that because of staff cutbacks, including the elimination of up to 950 New Jersey jobs, the quality of service provided to PSE&G customers, as well as the livelihoods of those PSE&G employees who provide those services, will be threatened. Ibid. UWUA and Local 601 argue that such considerations favor the application of a positive benefits standard to the Board's review of the impact of the proposed transaction on customers, [*35] as well as the no harm standard with respect to the statutory criteria. Ibid. UWUA and Local 601 also argue that the Board should ensure the no harm standard is applied consistent with its plain meaning so that there will be no adverse impact on any of the statutory factors. Id. at 5. UWUA and Local 601 assert that it appears that the Joint Petitioners may seek to have something less than a no harm standard applied in evaluating the impact of the proposed acquisition on PSE&G employees, and they express concern that the Joint Petitioners are attempting to redefine "no
harm" to mean "some harm," which they allege may be due to the Joint Petitioners' plan to cut up to 950 New Jersey jobs. Id. at 6. UWUA and Local 601 are concerned that such a standard would adversely impact both the quality of service and employees of PSE&G. Id. at 7.

REPLY COMMENTS

Joint Petitioners

The Joint Petitioners begin their reply by arguing that the legal standard to be applied in any proceeding must not be based on the identity of the parties. Joint Petitioners Reply Brief at 2. They contend that to "set a varying standard based on the applicant's identity is an invitation [*36] to inappropriate, even random behavior and possibly unfairness." Ibid. The Joint Petitioners also assert that Board Staff's references to the history of the Board, energy problems in California, and Enron are "irrelevant to the type of reasoned decision-making that the Board should pursue in this matter." Id. at 2 n.1. Referring to the initial briefs of the RPA, Board Staff, and NJCA, the Joint Petitioners argue that the positive benefit standard of review positions set forth therein, which they assert are based on size, are illogical. They claim, however, that, in any event, positive benefits to PSE&G and its ratepayers will result from the proposed transaction. Ibid. The Joint Petitioners further assert that claims that the merger will result in weakening the combined companies' financial position and unacceptable job losses are speculative. Ibid. The Joint Petitioners further argue that even if the transaction, by virtue of its size and significance, would present unusual risks, that is not a basis to apply the positive benefits standard over the no harm standard. Id. at 3. They note that in FirstEnergy, which they assert involved a not insignificant transaction, [*37] the Board applied the no harm standard, and they claim that, apart from speculative fears and the fact that this transaction is larger, no party herein has offered any basis to depart from the standard used in that case. Ibid.

The Joint Petitioners also repeat the argument that cases purporting to use the positive benefits standard have generally involved special circumstances not relevant here. Id. at 4. They also argue that the RPA has taken Commissioner Butler's dissent in FirstEnergy out of context. Ibid. In contrasting this case with FirstEnergy, the Joint Petitioners assert that PSE&G's service quality performance has been exemplary, and that PSE&G will remain a separate corporation headquartered in Newark and that Ralph Izzo will remain president and chief operating officer of PSE&G with the necessary authority and resources to ensure the continued provision of safe and adequate service. Ibid.

The Joint Petitioners further argue that while several parties have identified specific benefits provided by the merging parties in prior change of control cases, the fact that the Board may consider the benefits of a transaction does not provide any guidance [*38] regarding how a positive benefits standard would be applied. Id. at 5. They contend that the no harm standard "will allow the Board to consider all impacts of this transaction, including the numerous positive benefits, and ensure continued provision of safe and adequate service at just and reasonable rates." Ibid.

Ratepayer Advocate

The RPA notes that the majority of the parties who submitted initial briefs agree that positive benefits is the appropriate standard of review to be applied to this merger petition and that only the Joint Petitioners call for a no harm standard of review. RPA Reply Brief at 2-3. Noting that NJLEUC and RESA characterize the standard they propose as "no harm with positive conditions attached," the RPA asserts that this is equivalent to positive benefits. Ibid.

The RPA contends that while the Joint Petitioners seem to argue that the Board does not have the authority to amend its policy on merger review, it is well settled that the Board has broad powers over all aspects of public utilities subject to its jurisdiction and that this sweeping regulatory jurisdiction includes determination of the applicable standard of review. Id. [*39] at 3. The RPA further argues that contrary to the Joint Petitioners' claim that the Board is changing the rules in the middle of the game, the Board has reasonably decided to handle this issue early in the review process. Id. at 4. The RPA asserts that while the Joint Petitioners seem to argue that the Board only has authority to consider the
appropriate standard of review after the development of a factual record, this would place the parties in the undesirable
position of having to develop a record and form positions on the issues based on an unknown standard of review. Ibid.
The RPA argues that deciding the standard of review now will avoid any confusion while the case is being litigated,
rather than "create unnecessary confusion" as the Joint Petitioners suggest. Ibid.

The RPA also asserts that the Board should, in this case, continue its policy of deciding the applicable standard of
review by examining the individual circumstances of the merger before it. Id. The RPA notes that the Joint Petitioners
acknowledge that the Board, on previous occasions, has explicitly applied the positive benefits standard in cases in
which special circumstances existed. Id. at [*40] 5. The RPA argues that the Joint Petitioners ignore the fact that their
proposed merger presents its own unique set of special circumstances. Ibid. The RPA maintains that special
circumstances of the proposed transaction include a seventy-nine billion dollar transaction that would terminate the
independence of New Jersey's largest electric and gas public utility while creating the largest utility in the United States.
Ibid. The RPA also notes that the proposed combined utility would be the largest power generator in the country and
would maintain over twenty nuclear facilities. Ibid. The RPA contends that such a magnitude is unprecedented both
within New Jersey and on a national level and that the potential harm to New Jersey's ratepayers and other interested
parties is likewise unprecedented. Ibid. The RPA alleges that the proposed merger also is unique in that it has the
potential to adversely affect not only PSE&G's customers but also all electricity users in the State, and cites to the Joint
Petitioners' admission that the proposed merger creates significant market power issues that need to be corrected before
the merger could be approved. Id. at 6. The RPA [*41] concludes that given these unique circumstances, the positive
benefits standard is essential to protecting the public interest of New Jersey. Id. at 5-6. The RPA argues that even if the
Board accepts the Joint Petitioners' argument that the positive benefits standard should only be used in unique cases, the
Joint Petitioners' own testimony proves that this case is sufficiently unique to justify using the positive benefits
standard. Id. at 6. The RPA also notes that the Joint Petitioners repeat in their initial brief, as set forth in their Verified
Joint Petition, that they will show positive benefits in this transaction; therefore, the RPA alleges that it is inexplicable
for the Joint Petitioners to resist evaluation under a standard of review that they repeatedly assert they can satisfy. Ibid.
The RPA asserts that the Board would be remiss to rely on the Joint Petitioners' representations of positive benefits
without subjecting them to strict regulatory review. Id. at 7.

Utility Workers Union of America, AFL-CIO, and UWUA Local 601

UWUA and Local 601 contend that the Joint Petitioners' argument to adopt a "flexible balancing test," which UWUA
and Local [*42] 601 assert is a watered-down no harm standard, would impose significant harm upon the interests
specified in N.J.S.A. 48:2-51.1. UWUA and Local 601 Reply Brief at 2. They allege that Joint Petitioners cite no case in
which the Board has permitted the use of this standard, and they contend that even if it has been used elsewhere, the
unprecedented size and scope of the acquisition proposed in the instant proceeding make this acquisition a particularly
poor candidate for using such a standard. Ibid. Therefore, UWUA and Local 601 argue that the Board should reject the
Joint Petitioners' request for the adoption of a diminished no harm standard. Ibid.

UWUA and Local 601 further argue that the Joint Petitioners' claim that Board precedent precludes application of the
positive benefits standard is wrong, and they note that the Board determines the standard of review on a case-by-case
basis. Ibid. They assert that the Board has used the positive benefits standard where deemed appropriate and that even
where the Board has used the no harm test, it has still referred to the positive benefits test as a possible alternative. Id.
[*43] at 2-3. Therefore, UWUA and Local 601 argue there is no basis for the Joint Petitioners' argument that a positive
benefits standard would "change the rules in the middle of the game." Id. at 3.

UWUA and Local 601 also claim that, contrary to the Joint Petitioners' argument, the Board has provided the requisite
clarity for both the no harm and positive benefits standards in numerous cases, and has applied the positive benefits
standard in appropriate circumstances. Ibid. To the extent that further guidance is needed, UWUA and Local 601 assert
that the Board had delineated twelve factors that bear upon the positive benefits standard in New Jersey Resources
UWUA and Local 601 further contend that the Board should reject the Joint Petitioners' attempt to rewrite the no harm standard into a flexible balancing test in which the proposed acquisition could be approved notwithstanding that it would result in significant harm to employees and other factors in the statute. Id. at 3-4. They maintain that it is clear from the Board's decisions that the no harm finding is not to be made on an aggregate basis in which harm on one criterion can be disregarded upon a showing of benefits with respect to another criterion, but rather, a separate no harm finding must be made for each of the statutory criteria. Id. at 4. UWUA and Local 601 argue that if the Board adopts the "flexible balancing test," it should require the Joint Petitioners to demonstrate that any alleged positive benefit against which the Joint Petitioners propose to balance acquisition-related harms could not be obtained without the proposed acquisition. Id. at 5. UWUA and Local 601 also argue that a single job cut without significant mitigation would clearly violate the no harm standard, but they contend that the Board does not have to rule on the significance of a single job loss because the Joint Petitioners' example of a single job cut bears no resemblance to the Joint Petitioners' plan to eliminate 950 New Jersey jobs. Ibid.

UWUA and Local 601 also assert that the Joint Petitioners' reliance on Board precedent to support their request for adoption of a standard under which the proposed acquisition may be approved despite a finding that there will be substantial harm to employees is misplaced. Id. at 6. They argue that whether the no harm standard or the positive benefits standard is applied, the Board should, consistent with precedent and the plain meaning of those standards, act to ensure that neither utility employees nor the quality of service is adversely affected, or should ensure that they are positively benefited. Ibid. UWUA and Local 601 conclude by stating that if the Board agrees with the Joint Petitioners' interpretation that the no harm standard would permit the proposed acquisition to go forward even in the face of a finding that the acquisition would result in harms to some of the statutory criteria, the Board should insist upon application of the positive benefits standard. Id. at 7.

DISCUSSION

The Board has carefully considered the submissions by the parties, as well as the parameters of the proposed transaction itself. Having done so, for the reasons set forth below, the Board FINDS that in considering the requests of the Verified Joint Petition for approval of the acquisition of control of PSE&G as contemplated by the Agreement and Plan of Merger attached to the Verified Joint Petition as Exhibit JP-1C and the transfer of PSE&G's common stock, and in undertaking the evaluation required by N.J.S.A. 48:2-51.1, the Board should utilize a positive benefits standard of review.

With regard to its requests for Board approval of the acquisition of control of PSE&G and the transfer of PSE&G's stock, the Verified Joint Petition indicates that it was filed pursuant to N.J.S.A. 48:2-51.1 and N.J.S.A. 48:3-10, and provides information required by N.J.A.C. 14:1-5.10 and N.J.A.C. 14:1-5.14. N.J.S.A. 48:2-51.1 describes four specific factors to be evaluated by the Board when considering a request to acquire or seek to acquire control of a public utility, directly or indirectly. In particular, the statute requires the Board to evaluate the effect of the proposed acquisition on: (1) competition; (2) the rates of ratepayers affected by the acquisition of control; (3) the employees of the affected public utility or utilities; and (4) the provision of safe and adequate utility service at just and reasonable rates. Specifically, N.J.S.A. 48:2-51.1 [*47] provides:

No person shall acquire or seek to acquire control of a public utility directly or indirectly through the medium of an affiliated or parent corporation or organization, or through any other manner, without requesting and receiving the written approval of the Board of Public Utilities. Any agreement reached, or any other action taken, in violation of this act shall be void. In considering a request for approval of an acquisition of control, the Board shall evaluate the impact of the acquisition on competition, on the rates of ratepayers affected by the acquisition of control, on the employees of the affected public utility or utilities, and on the provision of safe and adequate utility service at just and reasonable rates. The Board shall accompany its decision on a request for approval of an acquisition of control with a written report.
detailing the basis for its decision, including findings of fact and conclusions of law.

As to the Verified Joint Petition's proposed transfer of stock, unless authorized by the Board, \textit{N.J.S.A. 48:3-10} prohibits the transfer or sale of capital stock by a public utility to another public utility \([*48]\) or to any corporation or person if the result of the sale or transfer in itself or in connection with previous sales or transfers would vest in such corporation or person a majority in interest of the public utility's outstanding capital stock. This statute provides that if, as a result of a proposed assignment, transfer, contract, or agreement for assignment or transfer of capital stock, it appears that the public utility or a wholly owned subsidiary thereof may be unable to fulfill its obligation to any of its employees with respect to pension benefits previously enjoyed, whether vested or contingent, the Board shall not grant its authorization unless the public utility seeking the Board's authorization assumes such responsibility as will be sufficient to provide that all such obligations to employees will be satisfied as they become due.

Nothing in \textit{N.J.S.A. 48:2-51.1} expressly suggests or requires how or under what standard of review the Board should consider a request for approval of an acquisition of control and evaluate the impact of an acquisition of control on the four criteria set forth in \textit{N.J.S.A. 48:2-51.1} \([*49]\). Nor does \textit{N.J.S.A. 48:3-10} or any other New Jersey statutory provision set forth an express requirement that the Board use a particular standard of review when considering a proposed acquisition of control of a public utility under the Board's jurisdiction. The Board has long considered the standard of review to be applied in reviewing acquisitions of control on a case-by-case basis and generally has considered whether to apply a no harm standard or a positive benefits standard, also sometimes referred to as the best interests of the public standard. See, e.g., Order of Approval, I/M/O the Petition of NUI Utilities, Inc. (d/b/a Elizabethtown Gas Company) and AGL Resources Inc. for Authority under \textit{N.J.S.A. 48:2-51.1} and \textit{N.J.S.A. 48:3-10} of a Change in Ownership and Control ("NUI"), Docket No.GM04070721 (November 17, 2004), at 5-6. In determining the standard of review to be applied herein, the Board has considered a no harm standard as requiring the petitioners to show and the Board to be satisfied that, at a minimum, there would be no adverse impact \([*50]\) on the provision of safe, adequate and proper service at just and reasonable rates and no adverse impact on the other criteria delineated in \textit{N.J.S.A. 48:2-51.1}, and a positive benefits standard as requiring the petitioners to show and the Board to be satisfied that positive benefits will flow to customers and the State as a result of the proposed change in control, and, at a minimum, that there are no adverse impacts on any of the criteria delineated in \textit{N.J.S.A. 48:2-51.1}.

In considering the standard of review to be applied herein, the Board is cognizant that, as the Joint Petitioners assert in their Verified Joint Petition and in their written submissions on this issue, and as other parties recognize as well, the Board has determined, on a case-by-case basis, to apply a no harm standard in reviewing a number of recent petitions for approvals of acquisitions of electric utilities. n3 See, Order, I/M/O the Petition of Atlantic City Electric Company and Conectiv, Inc. for Approval of a Change in Ownership and Control ("Conectiv"), Docket No. EM97020103 (January 7, 1998); Order. \([*51]\) I/M/O Consideration of the Joint Petition of Orange and Rockland Utilities, Inc. for Approval of the Agreement and Plan of Merger and Transfer of Control ("RECO"), Docket No. EM98070433 (April 1, 1999); Order of Approval, I/M/O the Joint Petition of FirstEnergy Corp. and Jersey Central Power & Light Company, d/b/a GPU Energy, for Approval of a Change in Ownership and Acquisition of Control of a New Jersey Public Utility and Other Relief ("FirstEnergy"), Docket No. EM00110870 (October 9, 2001); Order of Approval, Petition of Atlantic Electric Company, Conectiv Communications, Inc. and New RC, Inc. for Approval Under \textit{N.J.S.A. 48:2-51.1} and \textit{N.J.S.A. 48:3-10} of a Change in Ownership and Control ("PEPCO"), Docket No. EM01050308 (July 3, 2002). In Conectiv, the Board found that the facts of that matter did not demand use of a positive benefits standard, and that the use of a no harm standard in that matter was sufficient to ensure the continuation of safe, adequate and proper service at reasonable rates and adherence to the other requirements of \textit{N.J.S.A. 48:2-51.1} \([*52]\). Conectiv, at 6. Thereafter, in RECO, at 4, FirstEnergy, at 7, and PEPCO, at 12-13, the Board largely relied upon its ruling in Conectiv, in determining to apply a no harm standard in each of these particular cases.

n3 The no harm standard has been applied in evaluating other acquisitions of control as well. See, e.g., Order
The Board herein is cognizant, too, that although the Board in the foregoing cases stated that it was utilizing a no harm standard of review, the Board in these matters also considered the appropriate treatment of the acquisition's claimed benefits, including but not limited to, merger savings, and examined whether benefits had been properly derived and equitably shared with ratepayers. See, Conectiv, at 6-8; RECO, at 5; FirstEnergy, at 7; PEPCO, at 24-25. In fact, the Board's regulations governing petitions for approval of a merger or consolidation of a New Jersey public utility with that of another public utility have long required information regarding "the various benefits to the public and the surviving corporation which will be realized as the result of the merger." N.J.A.C. 14:1-5.14(a)(10).

Thus, irrespective of the use of a no harm test, the Board has required and examined information on benefits of acquisitions of control as an integral part of its analysis. Indeed, in FirstEnergy, the two-Commissioner majority approved the proposed acquisition at issue therein based, in part, on their findings, among other things, that customers would receive the benefits of merger synergy savings through a reduction in the utility's deferred balance, that FirstEnergy was committed to improving the utility's reliability and customer service performance, and that certain additional merger-related societal benefits would be provided (FirstEnergy, at 20-22, 24-30, 33-35), while Commissioner Butler dissented from approving the merger because the merger, in his view, provided "no real benefit to the ratepayers." FirstEnergy, at 37 (Frederick F. Butler, Commissioner, dissenting).

In NUI, the most recent petition involving an acquisition of control of an electric or gas utility to come before the Board, the Board discussed the above-referenced Orders and the determinations therein to utilize a no harm standard. NUI, at 6. With regard to the acquisition at issue in NUI, the Board determined that it was "appropriate to expand the scope of its review to capture expectations for improvements, e.g., some positive benefits." NUI, at 6. The Board explained that it was so finding because the utility entered "the process with credit ratings below investment grade, restricted access to capital markets, very high interest rates on existing lines of credit, significant prepayment burdens under its gas procurement arrangements, and a serious need to reestablish the trust and confidence of ratepayers, bondholders, and investors," problems which the Board emphasized had been caused by the parent company. NUI, at 6-7. In considering the acquisition's impact on rates under a proposed Stipulation of Settlement, the Board in NUI stated:

In determining whether the proposed merger is in the public interest, a primary concern of this Board is how the proposed merger will impact ETG customers. In evaluating whether a merger will harm customers, the Board tries to determine whether the merger will produce savings, what the cost of achieving those savings will be, and how rates will be impacted as a result of the merger. The Board then seeks to balance the interests of shareholders, who would receive the benefit of any increased share value resulting from the merger, with the interests of customers.receive the benefit of any increased share value resulting from the merger, with the interests of customers.

[NUI, at 10-1 (emphasis supplied).]

The Board found that the Stipulation of Settlement would not result in any harm to the rates of customers and that, in fact, pursuant to the Stipulation, the merger would provide "definitive benefits to customers" and "help to provide some rate stability during a period of volatile energy costs." NUI, at 11. The Board concluded that, under the
unique circumstances presented therein, the Stipulation "represents a fair and reasonable sharing of the potential benefits of the merger between customers and shareholders." NUI, at 11. It also concluded that subject to the conditions in the Stipulation and Board's Order, the change in control could be accomplished without any adverse impact on the statutory criteria. NUI, at 21.

While the several foregoing decisions have in some respects considered benefits of acquisitions, in other decisions the Board has explicitly indicated that it was utilizing a positive benefits or best interest of the public test. Prior to the enactment of N.J.S.A. 48:2-51.1, in In re New Jersey Natural Gas Company ("New Jersey Natural Gas"), Docket No. 695-342, 80 P.U.R. 3d 337 (September 11, 1969), the Board used a best interest [*57] of the public test in reviewing a stock transfer under N.J.S.A. 48:3-10. In its decision authored by then Board President and later New Jersey Governor Brendan Byrne, the Board explained:

The board of public utility commissioners is charged under N.J.S.A. 48:3-10 with the obligation to pass upon proposed stock transfers by the utility itself where, as here, the transfer will result in the creation of a foreign and wholly owned subsidiary in New Jersey. We think it necessary that the proposed transaction meet the test that it is in the best interest of the New Jersey consumers. In enunciating this test we are not unmindful of a host of decisions which refer to a different test, to wit, that the transaction will not adversely effect the ability of the utility to render safe, adequate, and proper service to customers.

A close analysis of the cited cases does not indicate that the board intends to adopt a negative test. Indeed, where facts have been recited in those opinions, it is quite apparent that those facts satisfy what we will call the "best interest of the public" test. In any event we [*58] believe that the legislative intent and the entire philosophy of regulation in New Jersey would require no less strict a test.

[New Jersey Natural Gas, 80 P.U.R. 3d at 339 (citations omitted).]

The Board further explained that within that standard, factors bearing on the public interest include: the effect of foreign or absentee ownership, elimination of competition, the integration of corporate structures, the increased or decreased financial capacities and flexibility, the impact on service standards, interference with regulatory jurisdiction, the promotion of economies, the effect on rates, and the maintenance of financial integrity. New Jersey Natural Gas, 80 P.U.R. 3d at 339.

By Decision and Order on Motions for Emergent Relief in I/M/O the Petition of New Jersey Resources Corporation and New Jersey Natural Gas Company v. NUI Corporation and Elizabethtown Gas Company, ("New Jersey Resources"), Docket No. 8312-1093, 57 P.U.R. 4th 709 (January 31, 1984), the Board again discussed use of a positive benefit standard. New Jersey Resources involved a proxy contest [*59] by which NUI Corporation ("NUI"), which wholly-owned a public utility, sought to replace a majority of the board of directors of New Jersey Resources Corporation ("NJR"), which wholly-owned another utility, with directors who were committed to merge the two utilities. The Board emphasized that in the event that NUI were successful in replacing a majority of the NJR board of directors, the Board would hold plenary hearings to determine whether the proposed merger is in the public interest, and it specified the criteria which would be utilized to evaluate the planned merger. n4 The Board also indicated that the proponents of the merger would have the burden of proof to establish that the merger is in the public interest. Citing New Jersey Natural Gas, supra, the Board concluded that "the basic standard that must be established is that the planned merger must be of positive benefit to the public interest and not merely that it would not adversely affect the ability of the merged utilities to provide safe, adequate and proper service at reasonable rates." The Board then enumerated the factors that bear upon such a standard as including:

1 The advantages [*60] of combined control as opposed to local management; in this case, the question of "absentee ownership" by out-of-state or foreign corporations does not arise;
2. The effect of the merger upon the competitive situation of the gas utility industry in this State; are there monopolistic concerns with respect to the planned merger?

3. The advantages and disadvantages of the integration of corporate structures;

4. The impact upon the financial capacity and flexibility of the merged utilities. This involves questions of utility capitalization and earnings sufficiency;

5. The reasonableness and cost benefit of the acquisition costs and the expenses of the proxy contest, as well as the appropriate accounting and rate treatment thereof;

6. The question of the maintenance of the financial integrity of two separate operating companies under the umbrella of one proposal [sic] combined utility;

7. The impact of the planned merger on service standards and continued provision of safe, adequate and proper service; this involves the key question of the impact of the planned merger on the assurance and flexibility of gas supply, both under normal and emergency conditions;

8. The effect [*61] of the planned merger on rates to be charged to the consumers both now and in the foreseeable future;

9. The effect of the merger on the customer mix and projected demand forecasts;

10. The effect of the planned merger on operating costs and the promotion of economies;

11. The impact on the Board's regulatory authority to exercise effective regulatory control on behalf of the public interest; and

12. The effect on obligations to employees with respect to pensions and other benefits pursuant to N.J.S.A. 48:3-7 and N.J.S.A. 48:3-10.

[New Jersey Resources, at 7-8.]

n4 The Board notes that New Jersey Resources was voted on at an agenda meeting four days prior to N.J.S.A. 48:2-51.1 being signed into law and the written Order was issued on the same date as N.J.S.A. 48:2-51.1 was signed into law. The Statement accompanying the bill which became N.J.S.A. 48:2-51.1 states that the purpose of the bill is to clarify current law to confirm that the direct or indirect acquisition of control of any public utility requires the prior approval of the Board. Statement, Assembly Bill No. 826 (1984). The Legislature did not incorporate a standard of review in the legislation, and can be presumed to be cognizant that the Board would, as it had, determine the standard or manner by which to conduct its evaluation of a proposed acquisition of control. Cf., Macedo v. Dello Russo, 178 N.J. 340, 346 (2004) (Legislature is assumed to be conversant with judicial constructions of its statutes); Avalon Manor Improvement Ass'n, Inc. v. Tp. of Middle, 370 N.J.Super. 73, 103 (App. Div. 2004) (Legislature is presumed to be aware of relevant case law when it enacts statutes), certif. denied, 182 N.J. 143 (2004).
While New Jersey Resources has often been distinguished as involving a standard of review to be applied in the context of a hostile takeover, upon further reflection, the Board finds nothing therein which draws a distinction on that basis in determining the applicable standard of review. Indeed, the Board's reference in New Jersey Resources to "the basic standard," its citation to New Jersey Natural Gas, which did not involve an acquisition of control resulting from a hostile takeover, and the enumerated factors, other than proxy contest expenses, bearing upon the standard of review, lead to the contrary conclusion, i.e., that the Board in New Jersey Resources was enunciating the standard it concluded would be applicable to the proposed merger, irrespective of its derivation. Indeed, from the perspective of customers and the public, the Board finds no basis to distinguish the applicable standard of review solely on the basis of whether or not a proposed acquisition of control has resulted from a proxy contest or other hostile takeover situation. What is of vital import to customers and the State is the effect of an acquisition of control on them subsequent to the acquisition, not how the proposed acquisition was derived prior to its effectuation.

As the foregoing reflects, the Board has, on a case-by-case basis, articulated that it was utilizing a no adverse impact or a positive benefits standard of review in reviewing proposed acquisitions of control of public utilities. The Board now turns to do so with regard to the proposed acquisition of control presently before the Board. The magnitude of the proposed transaction is plain from its description: PSE&G is one of the largest combined electric and gas companies in the United States and is also New Jersey's oldest and largest publicly owned utility. Even prior to the 1911 enactment of public utilities laws and the creation of the Board, the Public Service Corporation was formed over one hundred years ago in 1903 by amalgamating more than 400 gas, electric and transportation companies in New Jersey. Continuing a reference to the "public," which it was established to serve, and to "service," which it was established to provide, it was renamed Public Service Electric and Gas Company in 1948. See http://www.pseg.com/companies/pseandg/about.isp. PSE&G provides electric and gas service in areas of the State in which approximately 5.5 million people, about 70% of the State's population, reside. PSE&G's electric and gas service area is a corridor of approximately 2,600 square miles running diagonally across New Jersey from Bergen County in the northeast to an area below the City of Camden in the southwest. This service area encompasses most of the State's largest municipalities, including its six largest cities, Newark, Jersey City, Paterson, Elizabeth, Trenton and Camden, in addition to approximately 300 suburban and rural communities. The proposed merger would result in an entity with the largest electric utility holdings in the nation and would serve over seven million retail electric customers, as well as two million retail gas customers, including customers residing in Chicago and Philadelphia, the nation's third and fifth most populous cities. See, The World Almanac and Book of Facts 2005, at 626. The proposed merged entity also would be the country's largest power generator and a leading national wholesale power marketer with a generation portfolio of about 52,000 MW of domestic capacity, including about 20,000 MW of nuclear generation. Exelon Nuclear operates seventeen nuclear reactors, the largest string in the country and the third largest in the world, with the merger proposing to add PSEG Power's three nuclear facilities. Both Exelon and PSEG entities control substantial generation fleets in PJM. Thus, as Board Staff aptly asserted, by the proposed transaction, an already vast public utility on the national stage-and the largest public utility in both Illinois and Pennsylvania -- is seeking to acquire New Jersey's largest public utility, and the proposed transaction represents an unprecedented consolidation of power generation, including nuclear plants.

The potential risks to New Jersey associated with the size of the combined entity may be exacerbated by the imminent repeal of the Public Utility Holding Company Act of 1935 ("PUHCA"), 15 U.S.C.A. § 79 et seq., a Depression-era statute that regulates multi-state holding companies. PUHCA was enacted in response to the failure of a number of large multi-state utility holding companies. Through various fraudulent practices, the holding companies were able to increase rates for customers of the operating electric or gas utilities, and use the money from these captive ratepayers to prop up failing holding company ventures. The holding companies became so highly leveraged, all supported by the operating utilities at the bottom of the corporate pyramid, that when the banks called in the loans after the stock market crash of 1929, many of these companies quickly went bankrupt. The collapse of the utility holding company empires threatened the public interest by challenging the stability of the provision of utility service, a critical component of the country's infrastructure. PUHCA was enacted to protect investors, consumers and the public from future exploitation of electric and gas utility subsidiaries. See generally, The Public Utility Holding Company Act: Its
Protections Are Needed Today More Than Ever, American Public Power Association, Feb. 2003. As part of its analysis of the Verified Joint Petition and mindful of the imminent repeal of PUHCA, the Board must ensure that, if approved, the resulting entity, which would have the largest utility holdings in the United States, transcending multiple states and regions, will not participate in the same pre-PUHCA abuses that occurred in the 1920's and 1930's.

n5 The Board notes that subsequent to its consideration of the standard of review at its June 22, 2005 agenda meeting, the Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, was signed into law on August 8, 2005, and, as had been anticipated, it provides for PUHCA's repeal, effective six months thereafter. Pub. L. No. 109-58, §§ 1263, 1274(a).

Furthermore, New Jersey's retail electric customers are dependent upon competitive electric supplies acquired through the Board-authorized Basic Generation Service auction, bilateral agreements between customers and suppliers, or through PJM-operated energy and capacity markets. Structurally competitive markets are the necessary predicate for fair market prices paid by New Jersey electric customers, now and into the future. The development and maintenance of structurally competitive markets requires vigilance through market monitoring and the implementation of definitive mitigation measures where the potential or actual exercise of market power is evidenced. Under the subject petition, the acquisition of PSEG by Exelon would explicitly reduce the number of significant competitors in New Jersey wholesale markets by one as the Exelon and PSEG generation subsidiaries join to become a new, combined generation entity. Further, absent mitigation or other measures, the currently substantial market shares of each company in the relevant markets raises not merely the potential but rather the certainty of significantly higher market concentration and the potential future exercise of market power. The Joint Petitioners themselves recognize the problem of market power inherent in the proposed acquisition, viz. the Joint Petitioners' accompanying proposal for market power mitigation. See, Exhibit JP-6, Direct Testimony of Rodney Frame. Thus, as noted by the Ratepayer Advocate, the proposed merger has the potential to adversely affect not only the customers of the utility directly involved, PSE&G, but also all users of electricity in the State. RPA Reply Brief at 6.

The Board concurs with the Ratepayer Advocate that "as the facts to date have shown, the review of this case is so vital to the interests of all customers in New Jersey, that the use of the positive benefits standard is fully justified." RPA Reply Brief at 6. Furthermore, the Board concurs with its Staff that "consideration of this merger must recognize the fragility which underlies delivery of energy in this twenty-first century. The recent specters of the California blackouts/energy fraud and Enron debacle and the summer of 2003 blackout of the entire Northeast underscore the obligation of regulators to exercise their responsibility under the highest lawful standards." Board Staff Initial Brief at 3. Indeed, the fragility of energy delivery and consequences to the public were highlighted to this Board by the reliability problems of one of the State's own electric utilities, Jersey Central Power & Light Company. Occurring subsequent to the merger approved in the FirstEnergy Order, the reliability problems caused extensive outages at the New Jersey shore over the July 4, 2003 holiday weekend and led the Board to undertake a reliability audit, appoint a Special Reliability Master, and take certain rate-related actions in order to ensure improvements to service. See, Order, I/M/O the Board's Investigation into JCP&L's Outages of the July 4, 2003 Weekend and the Focused Audit of Jersey Central Power and Light Company, Docket Nos. EX03070503 and EX02120950 (March 29, 2004); Decision and Order Adopting Stipulations of Settlements Approving Phase II Rate Increase and Resolving Motion and Cross Motion for Reconsideration, I/M/O the Verified Petition of Jersey Central Power and Light Company for Review and Approval of an Increase in and Adjustments to Its Unbundled Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith, et als., Docket Nos. ER02080506, ER02080507, EO02070417, ER02030173, ER95120633 (May 31, 2005). The Board disagrees with the Joint Petitioners' claim that Board Staff's arguments and considerations in this regard are irrelevant to the Board's decision-making herein. To the contrary, administrative agencies performing quasi-legislative functions are generally entitled to avail themselves of general
information and expert knowledge which they may obtain in the performance of day to day administrative activities. City of Passaic v. Passaic County Bd. of Taxation, 18 N.J. 371, 384 (1955). [*71] Agencies do not "operate in a vacuum" and are not required "to act upon particular applications with eyes and mind completely averted from a known situation." In re Shore Hills Water Co., 101 N.J. Super. 214, 226-27 (App. Div. 1968). The Board concurs with its Staff that recent blackouts and other events have highlighted the "fragility which underlies delivery of energy in this twenty-first century" and underscore the need to evaluate the proposed transaction under a standard which will best assure that the acquisition of control will be of benefit to customers and the State, notwithstanding the risks involved. Given the fragility of energy delivery and the substantial risks involved with the proposed change in control for which the Board's approval is sought, the Board of Public Utilities, in fulfilling its duties to the public, is compelled to require a showing that the proposed acquisition of control will result in positive benefits to customers and the State of New Jersey.

In considering the standard to be applied in reviewing the proposed acquisition, the Board also is cognizant of the legislative findings in enacting the Electric Discount [*72] and Energy Competition Act, N.J.S.A. 48:3-49 et seq., and finds that its duties under N.J.S.A. 48:2-51.1 and N.J.S.A. 48:3-10 to consider the acquisition of control and stock transfer at issue herein should not be considered in isolation but should be considered in pari materia with EDECA and harmonized with the intent expressed therein. See, State in re G.C., 179 N.J. 475, 481-82 (2004); State v. Malik, 365 N.J. Super. 267, 276 (App. Div. 2003), certif. denied, 180 N.J. 354 (2004); Barron v. State Health Benefits, 343 N.J. Super. 583, 587 (App. Div. 2001). In enacting EDECA, the Legislature declared as policy of this State, among other things, to: "Lower the current high cost of energy, and improve the quality and choices of service, for all of the State's residential, business and institutional consumers, and thereby improve the quality of life and place this State in an improved competitive position [*73] in regional, national and international markets"; "Place greater reliance on competitive markets, where such markets exist, to deliver energy services to consumers in greater variety and at lower cost than traditional, bundled public utility service"; "Ensure universal access to affordable and reliable electric power and natural gas service"; "Provide diversity in the supply of electric power throughout this State"; "Prevent any adverse impacts on environmental quality in this State as a result of the introduction of competition in retail power markets in this State"; "Ensure that improved energy efficiency and load management practices, implemented via marketplace mechanisms or State-sponsored programs, remain part of this State's strategy to meet the long-term energy needs of New Jersey consumers"; "Preserve the reliability of power supply and delivery systems as the marketplace is transformed from a monopoly to a competitive environment"; and "Provide for a smooth transition from a regulated to a competitive power supply marketplace, including provisions which afford fair treatment to all stakeholders during the transition." N.J.S.A. 48:3-50(a)(1) [*74], (2), (4), (7), (9), (10), (11) and (12). The Legislature also found and declared, among other things, that "the traditional electric public utility rate regulation which the Board of Public Utilities has exercised over retail power supply in this State requires reform in order to provide retail choice and bring the benefits of competition to all New Jersey consumers." N.J.S.A. 48:3-50(b)(5). Based on these and other findings set forth in N.J.S.A. 48:3-50(a) and (b), the Legislature determined that it is in the public interest to: (1) "Authorize the Board of Public Utilities to permit competition in the electric generation and gas marketplace . . . and thereby reduce the aggregate energy rates currently paid by all New Jersey consumers"; (2) "Provide for regulation of new market entrants in the areas of safe, adequate and proper service and customer protection"; (3) "Relieve electric public utilities from traditional utility rate regulation" for services provided in a competitive market; (4) Provide electric public utilities "the opportunity to recover above-market power generation and supply costs [*75] . . . associated with the restructuring of the electric industry" subject to certain conditions; and (5) "Provide the Board . . . with ongoing oversight and regulatory authority to monitor and review composition of the electric generation and retail power supply marketplace in New Jersey, and to take such actions as it deems necessary and appropriate to restore a competitive marketplace in the event it determines that one or more suppliers are in a position to dominate the marketplace and charge anti-competitive or above-market prices." N.J.S.A. 48:3-50(c); In re Public Service Electric & Gas Company's Rate Unbundling, 167 N.J. 377, 383 n.1, cert. denied, 534 U.S. 813, 122 S.Ct. 37, 151 L.Ed. 2d 11 (2001).

The Board finds that the primary thrust of EDECA and the legislative intent manifested therein clearly is that there be improvements and benefits to the State and its consumers from the deregulation and restructuring of the State's electric
and gas public utilities, and the provision of access to competitively priced electricity,[*76] natural gas, and other energy related services formerly provided only by the State's regulated electric and gas public utilities. Construing N.J.S.A. 48:2-51.1 and N.J.S.A. 48:3-10 in harmony with the subsequently enacted EDECA, and in view of the magnitude of the proposed transaction at issue herein and the concomitant risks and potential ramifications thereof, the Board finds that the proposed acquisition of control and stock transfer should be evaluated by use of a positive benefits standard so as to further promote the receipt by customers and the State of the benefits intended by EDECA.

Moreover, the Board agrees with NJLEUC and RESA (NJLEUC and RESA Initial Brief, at 5) that review of the Verified Joint Petition under a positive benefits standard provides a measure of balance between the benefits anticipated to be derived by the utilities' other merging parties' officers and shareholders on the one hand, and customers, competitors and other stakeholders. The boards of directors of each merging entity have, respectively, determined that the merger is "advisable, fair to, and in the [*77] best interests" of Exelon and its shareholders and PSEG and its shareholders, and recommended that their respective shareholders vote in favor of the issuance of shares of Exelon common stock as contemplated by the merger agreement, and in favor of the proposal to approve the merger agreement, thereby approving the merger. Form S-4 at 9. While the Joint Petitioners indicate that they also have made an analysis of the benefits of the proposed transaction to be derived by their customers and others (See, Verified Joint Petition PP 14, 43), the directors and executive officers of PSEG and Exelon have financial and other interests which could have affected their decisions to support or approve the merger. See, Form S-4 at 24, 99-108. The Board finds that as a requisite for Board approval, it is manifestly appropriate, reasonable and in the public interest for a determination also to be made by the Board that the acquisition of control and transfer of stock will provide positive benefits to customers and the State, and to also consider whether there will be benefits for other stakeholders.

Public utilities, unlike most other corporations, are subject to a special obligation to serve[*78] the public interest, and their property is affected with a public interest. Matter of Valley Road Severage, 154 N.J. 224, 240 (1998). A public utility's franchise is a privilege of a public nature conferred by government to do that which does not belong to the citizens of the country generally by common right, and it provides permission to operate a business, peculiarly of a public nature and generally monopolistic. In re Petition of South Lakewood Water Co., 61 N.J. 230, 238 (1972). Unlike shareholders, customers receiving electric distribution, gas distribution, basic generation and/or basic gas supply services do not have their own vote on whether to approve the merger, yet they will continue to be in a position of having to take at least the distribution service from the utility under the proposed new corporate structure, and thus, be dependent on the utility in its new corporate structure for safe, adequate and reliable service. Just as shareholders are afforded the opportunity to evaluate the benefits and risks of a proposed merger and exercise their votes as they determine to be appropriate in view of their [*79] evaluation of the benefits and risks, it is in the public interest for the Board, which has been accorded the role of an independent agency entrusted by the Legislature with responsibilities for administering Title 48, to make an assessment of the benefits of the acquisition of control and stock transfer at issue for the customers and the State, and not only to make an assessment of the negative aspects or risks.

The Board notes that the Joint Petitioners recognize that in NUI, the Board was "arguably justified in wanting to see more than no harm' when a troubled utility was being acquired [because] no harm' would do nothing to resolve the serious operational and financial difficulties which threatened to impair service to customers"; however, the Joint Petitioners then argue that in the within matter, there are no such allegations and point to PSE&G as being "a healthy company with investment grade credit ratings, access to the capital markets, economic interest rates on its existing lines of credit, and trust and confidence of ratepayers and the financial community borne of decades of excellent service and financial performance." Joint Petitioners Initial Brief at 6; Joint [*80] Petitioners Reply Brief at 4. The Joint Petitioners also argue that this being a consensual merger, it is not a hostile takeover situation like in New Jersey Resources, and thus, they argue that there is no precedent for applying a positive benefits standard herein. Contrary to the implications of the Joint Petitioners' contentions, the Board does not believe that it is limited to requiring a showing of positive benefits only when an acquisition involves a utility in need of improvement or a utility which is part of a corporate structure with financial or other difficulties. Nor, as discussed above, does the Board conclude that the standard enunciated in New Jersey Resources is distinguishable because the merger therein derived from a proxy contest. Just as
there is an evaluation of whether a merger will be of benefit to shareholders, it is appropriate and in the public interest to evaluate whether there will be any benefits to customers and the State from a change in the current structure, which the Joint Petitioners maintain is serving customers well, to a structure which, on its face, appears to present substantial risks. The Board agrees with the UWUA and Local 601 that [*81] "the threats posed by the proposed acquisition . . . justify the exercise of great care in determining whether, and under what conditions, the proposed acquisition should be approved" and that "absent a showing of positive benefits, there would seem to be little reason . . . for the Board to risk the potential for acquisition-related harms." UWUA and Local 601 Initial Brief at 3.

Evaluating the proposed acquisition herein under a positive benefits standard is, as noted above, consistent with certain earlier decisions of the Board, consistent as well as with the Board's consideration in the past of benefits of mergers, even when a no harm standard was stated to be the governing standard, and consistent with the Board's regulations at N.J.A.C. 14:1-5.14(a)(10). As discussed above and as argued by the Ratepayer Advocate and others, even in those proceedings in which the Board has applied a no harm standard, the Board has often conditioned its approval on, among other things, the conferring of compensatory or positive benefits to ratepayers and other stakeholders. Indeed, as noted above, notwithstanding that they assert that the acquisition [*82] should be reviewed by determining whether it will not adversely impact upon the four areas specified in N.J.S.A. 48:2-51.1, the Joint Petitioners themselves have indicated in their Verified Joint Petition that the proposed merger "is expected to enhance operations and strengthen the combined ability of Exelon's utility subsidiaries to provide cost-effective, safe and reliable service and will affirmatively promote the public interest in a number of substantial ways." Verified Joint Petition at PP 14 and 21. According to the Verified Joint Petition, benefits of the merger include: an increased scale and scope in energy delivery, which will result in improved service and reliability; anticipated financial strength and flexibility, which will help ensure that PSE&G has continued access to capital at favorable rates; a sharing of best practices and coordination among operating utilities, which is expected to improve customer service and service reliability; economies, which, after "costs-to-achieve," will accrue to New Jersey jurisdictional regulated businesses of PSE&G, and help offset the rise in costs of providing reliable electric and [*83] gas distribution service, thereby giving rise, over time, to lower rates than would otherwise be the case; an enhanced ability to operate in competitive retail and wholesale markets, which in turn will continue to provide benefits for customers and shareholders; benefits to customers by reducing costs and maintaining or enhancing operations and reliability; more opportunities for employees in a larger, more competitive company; streamlining and increasing the efficiency of the process of procurement from suppliers; and benefits to the communities served by the combined company by having operating headquarters and a substantial corporate presence in Newark, New Jersey, as well as Chicago Illinois and Philadelphia, Pennsylvania; and by PSE&G continuing its support of economic development in New Jersey. Verified Joint Petition at PP 14(a) through (g). Even when discussing that the merger satisfies a no harm standard, the Verified Joint Petition discusses benefits. Verified Joint Petition at PP 22 through 37. See also, e.g., Exhibit JP-2, Direct Testimony of John W. Rowe, at 6-9, addressing "Benefits of the Merger" and concluding at 21, that "the Merger will create benefits [*84] for our customers, employees, shareholders and the communities served by PSE&G, which could not otherwise be achieved"; Exhibit JP-3, Direct Testimony of Ralph Izzo, at 3, stating, among other things, that "the merger should enhance PSE&G's ability to render safe and reliable service," and at 6-7, that, as discussed in testimony of William Arndt (Exhibit JP-4), the reduction in PSE&G's future costs of its electric and gas delivery operations due to the merger "will reduce the amount of any future rate relief required by the utility, thereby providing a direct benefit to customers" and concluding at 13, that "New Jersey will benefit from the Board's approval of this transaction." The Joint Petitioners also stated in their initial brief on the standard of review that they will show that there are positive benefits arising from the proposed transaction and, as well, in their reply brief, that "the Joint Petition is clear, and the record will further demonstrate, that the proposed transaction will bring many positive benefits to PSE&G and its ratepayers . . . ." Joint Petitioners Initial Brief at 6; Joint Petitioners Reply Brief at 2.

The Joint Petitioners, nevertheless, argue that "there [*85] is no basis, and certainly none at this time" to depart from what they term the "traditional no harm standard," which they also assert will still allow the Board to consider the numerous positive benefits of their proposed transaction. Joint Petitioners Initial Brief at 6. They claim that "it would be inappropriate, before the development of any factual record, to depart" from the no harm standard, and that there is no
evidence supporting the need for a positive benefits standard. Joint Petitioners Initial Brief at 2; Joint Petitioners Reply Brief at 5, 7. Contrary to the Joint Petitioners' assertions, the Board finds that there already is more than ample information before the Board, by the Verified Joint Petition and the prefiled direct testimony, for the Board to determine that the acquisition of control proposed herein should be evaluated by use of a positive benefits standard. Furthermore, contrary to the Joint Petitioners' contentions that the Board is somehow "changing the rules in the middle of the game" and departing from its precedent (Joint Petitioners Initial Brief at 2), the Board has, in its prior Orders, determined the applicable standard to be applied on a case-by-case [*86] basis based upon an examination of the circumstances of the particular proposed transaction, and that is what the Board is doing herein. The Board also finds that, at this juncture of the proceeding, prior to the commencement of evidentiary hearings, the clarification provided herein that the Board will use a positive benefits standard in evaluating the instant application will enable the Verified Joint Petitioners and indeed all parties a fair and reasonable opportunity to present their positions as to whether or not the standard has been met.

Accordingly, for the foregoing reasons, the Board HEREBY FINDS that in considering the Joint Petitioners' request for approval of the acquisition of control of PSE&G and the transfer of PSE&G's common capital stock proposed in the within matter and in undertaking the evaluation required by N.J.S.A. 48:2-51.1, the Board shall utilize a positive benefits standard of review. Pursuant to the positive benefits standard, in order for the proposed acquisition of control and transfer of stock to be approved by this Board, the Joint Petitioners must show and the Board must be satisfied that positive [*87] benefits will flow to customers and to the State as a result of the proposed change in control, and, at a minimum, that there are no adverse impacts on any of the criteria delineated in N.J.S.A. 48:2-51.1.

As a final matter, the Board notes that while it has determined the applicable standard for the review of the Verified Joint Petition in this matter, in order to determine and afford an opportunity to be heard as to whether to apply the standard of review set forth above to other matters, the Board will undertake a rulemaking proceeding and will hereafter propose a regulation to govern petitions to the Board for the acquisition of control of public utilities.

DATED: November 9, 2005

BOARD OF PUBLIC UTILITIES BY:

JEANNE M. FOX
PRESIDENT

FREDERICK F. BUTLER
COMMISSIONER

CONNIE O. HUGHES
COMMISSIONER

JACK ALTER
COMMISSIONER

Legal Topics:

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FERC REGULATORY DEVELOPMENTS

FERC Notice of Inquiry (NOI) on Market Power Analysis

• NOI issued in response to issuance by DOJ/FTC in 2010 of updated Merger Guidelines
  - More relaxed HHI standards for screen violations
  - Emphasis on alternative approaches to evaluating merger-related market power

• FERC asked in NOI whether it should follow the DOJ/FTC lead on both points

• Proposed revisions to FERC merger regulations expected in the near future
FERC REGULATORY DEVELOPMENTS

FERC Coordination With DOJ/FTC Review

- In two recent merger proceedings, FERC issued notice of intent to confer with DOJ/FTC
  - Duke-Progress
  - Exelon-Constellation
- FERC appears to want to coordinate with DOJ/FTC and avoid inadvertently taking inconsistent positions
- Understand that FERC may incorporate this practice into its merger regulations
FERC REGULATORY DEVELOPMENTS

Duke Progress Order

- FERC made clear that prices used for calculating Economic and Available Economic Capacity must be market-based. In areas not covered by RTOs, market-based prices must be derived from EQR data.
- FERC required Applicants to offer mitigation to eliminate screen failures not only in the Applicants’ base-case Available Economic Capacity analysis, but also in the plus/minus 10% price sensitivity cases.
- FERC departed from past practice of not requiring mitigation when screen failures were not systematic.
FERC REGULATORY DEVELOPMENTS

Increased Number of FERC Staff Requests for Supplemental Information

• In the last two years, FERC Staff has increasingly resorted to issuing letters requiring the submission of supplemental information
  ➢ Some letters have come shortly after submission of Application to address deficiencies
  ➢ Some letters have come after protests were filed to address information issues raised in the protests

• A potential effect is to restart the 180-day clock that FERC has to rule on an application
  ➢ In FirstEnergy-Allegheny Power, FERC relied on response to request for supplemental information to restart the initial 180 day time limit for its review
  ➢ In Exelon-Constellation, FERC relied on the filing of a settlement with the PJM Market Monitor as the basis to restart the 180 day time limit
FERC REGULATORY DEVELOPMENTS

Increased Length of FERC Review

• Until recently, FERC reviewed and issued orders in even the largest and most complex cases in 4 to 5 months
  ➢ Exelon-PSEG (extremely complex protests) – 5 months
  ➢ Duke-Cinergy – 5 months
  ➢ Great Plains-Black Hills-Aquila – 5 months
  ➢ Exelon-NRG (hostile transaction) – 5 months

• Since 2010, FERC has slowed down its review for larger cases
  ➢ FirstEnergy-Allegheny Power – 7 months
  ➢ Northeast Utilities-NSTR – 6 months
  ➢ Duke-Progress – 6 months, with requirement for mitigation filing
  ➢ AES-Dayton Power & Light – 6 months
  ➢ Exelon-Constellation – 6 months and counting
FERC REGULATORY DEVELOPMENTS

Market Definition in RTOs

• Typical FERC practice is to analyze RTOs as a single market
  ➢ Submarkets within RTOs not typically evaluated unless traditionally viewed as separate markets, *i.e.* PJM East

• As more data becomes available, it becomes easier to identify and justify additional submarkets

• In Exelon-Constellation filing, applicants identified two new submarkets never before analyzed
  ➢ PJM Market Monitor then filed analysis of 34 separate constraints

• Evaluation of smaller submarkets within an RTO increases the potential that market power will be found
FERC REGULATORY DEVELOPMENTS

Hold Harmless Rate Commitments

• Merger applicants typically include hold harmless rate commitments in their application
  ➢ Merger-related costs will not be included in cost-based power sales and transmission rates unless offset by merger-related savings

• FERC recently has considered how these commitments apply to formula rates, e.g. transmission revenue requirements for RTOs
  ➢ Demonstration of compliance required in formula rate filings

• Potential issue when upfront costs to achieve savings, such as employee buy out costs, but savings are achieved over a number of years
  ➢ Need to request permission to amortize costs over a number of years
FERC REGULATORY DEVELOPMENTS

Cross Subsidization Issues

• Under 2005 EPAct Amendments to FPA, FERC required in merger proceedings to consider cross-subsidization of unregulated affiliates by regulated utilities

• Issue typically arises where merger appears to trigger a credit downgrade of a public utility with captive customers

• Ringfencing usually required to address cross subsidization concerns
STATE REGULATORY DEVELOPMENTS IN UTILITY M&A
STATE REGULATORY DEVELOPMENTS

Expansion of State PUC Jurisdiction Over Merger Transactions

- State PUCs have started reading their merger statutes more broadly to assert jurisdiction over merger transactions
  - Maryland PSC jurisdiction over EDF purchase of 49.9% of Constellation’s unregulated nuclear subsidiary
  - New York PSC jurisdiction over sale of EWGs
  - New Jersey BPU requiring settlement for FirstEnergy acquisition of Allegheny Power
  - Arguments in Connecticut that jurisdiction should be asserted over Northeast Utilities’ acquisition of NSTAR
    - These arguments rejected by PSC
STATE REGULATORY DEVELOPMENTS

Movement Towards Net Benefits Test

• Two approaches towards evaluating mergers
  ➢ No net harm – on balance, merger must not harm public interest
  ➢ Net benefits – on balance, the benefits of merger must outweigh any harms, leaving a net benefit

• Practical difference is that, under a net benefits test, applicants have to offer up new benefits – typically rate reductions, while this is not required under a no net harm test

• FERC applies the no net harm test, and traditionally most states did as well

• Recently, many states have moved to the net benefits test, either by statutory amendment or by reinterpreting their existing statute
More Rigorous State PUC Review of Mergers

• When PUHCA was repealed in 2005, many people predicted that multistate mergers would become much easier and would proliferate

• However, short after PUHCA repeal, two multistate transactions were derailed by State PUC reviews
  - Exelon-PSEG
  - FPL-Constellation

• Concern arose that State PUC review would make multistate mergers more difficult, and the number of proposed mergers declined

• Some multistate mergers have been proposed recently
  - FirstEnergy-Allegheny Power (completed)
  - Northeast Utilities-NSTAR (pending)
  - Duke Energy-Progress Energy (pending)
  - Exelon-Constellation (pending)
STATE REGULATORY DEVELOPMENTS

Issues in State Merger Proceedings

- Rate Reductions
  - Especially in net benefits states
- Jobs and job retention
- Effects on local economy and local charitable contributions
- Effects on local quality of service
- Allocation of synergies achieved that are associated with unregulated affiliates
STATE REGULATORY DEVELOPMENTS

Ring-Fencing

- Another issue that frequently arises is the need for ring-fencing, *i.e.* insulating the regulated utility from adverse economic impacts on parent and/or unregulated affiliates.

- Recent examples
  - EDF-Constellation
  - Puget-Macquarie
  - Duquesne

- Typical ring-fencing provisions
  - Dividend restrictions
  - Minimum Debt-to-Equity ratio provisions
  - Independent directors
  - Issuance of own debt
  - No cross-collateralization
  - Non-consolidation opinions
STATE REGULATORY DEVELOPMENTS

State Evaluation of Merger-Related Wholesale Market Power Issues

• States located in RTOs have become increasingly interested in wholesale market power issues associated with proposed mergers
  ➢ RTO markets affect prices paid SOS service and that can be charged by competitive retailers
  ➢ State PUCs do not have much expertise in wholesale market power issues, but have become less willing to defer to review of wholesale market power issues by FERC and DOJ/FTC

• PJM Market Monitor twice invited to participate in state proceedings
  ➢ New Jersey – Exelon-PSEG
  ➢ Maryland – Exelon-Constellation
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Analysis of Horizontal Market Power Under the Federal Power Act Docket No. RM11-14-000

COMMENTS OF THE EDISON ELECTRIC INSTITUTE


**BACKGROUND**

The Commission established the competition analysis it uses in evaluating merger applications and applications for other transactions under Section 203 of the Federal Power Act ("FPA") in its 1996 Merger Policy Statement\(^2\) and four-year later Part 33 Regulations\(^3\) (together, "Section 203 Policy"). Therein, the Commission adopted

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1 EEI is the association of U.S. Shareholder-Owned Electric Companies. Our members serve 95% of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70% of the U.S. electric power industry. EEI also has as members more than 70 international electric companies, and as associate members, more than 200 industry suppliers and related organizations.


3 *Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,872 (2000).*

The Antitrust Agencies updated the 1992 Guidelines in August 2010 (“the 2010 Guidelines”). On the one hand, the 2010 Guidelines set higher thresholds than the earlier guidelines for the level at which post-merger market concentration would be deemed problematic by the Antitrust Agencies. On the other hand, the 2010 Guidelines placed a decreased emphasis on such “structural” competitive measures in the Antitrust Agencies' overall assessment of proposed mergers.

The Commission’s NOI asks for comments as to whether FERC should update its horizontal market power guidelines in the context of FPA Section 203 applications to conform more closely to the 2010 Guidelines. In particular, the Commission has posed the following two questions:

I. "[T]he 2010 Guidelines place less emphasis on market definition and the use of a prescribed formula for considering the effects of a merger than the 1992 Guidelines. Should the Commission adopt this approach?"

II. "The 2010 Guidelines’ reduced emphasis on market definition and prescribed formulas aside, should the Commission adopt the revised HHI levels in the 2010 Guidelines in its analysis of whether a proposed transaction will adversely affect competition under § 203 of the FPA?"

NOI at P 15. EEI's comments focus primarily on these two questions.

The Commission also requests comments regarding the relevance of revisions reflected in the 2010 Guidelines to the Commission's analysis of market-based rate

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Electric utility mergers and other transactions covered by FPA Section 203 can lead to substantial public benefits by, among other things, allowing companies to achieve economies of scale, share best-practices, and integrate technology, procurement, and administrative support operations. At the same time, it is possible that these benefits could be undermined if a merger or acquisition were to result in a material decrease in competition for the products and/or services offered by the merged companies. Therefore, it is important for the Commission to have in place a Section 203 review process that identifies and prevents transactions that might result in competitive harm, while not imposing restrictions on transactions that do not threaten to affect competitive outcomes.

EEI believes that the Commission's current methodology for analyzing the competitive effects of mergers and other transactions under Section 203 has been highly effective at precluding transactions that pose a threat of competitive harm while providing a relatively streamlined process for approving ones that do not. Although different in nature from the review conducted by the Antitrust Agencies, the Commission’s review is conservative and complements the merger review conducted by those agencies.

The Commission's Section 203 Policy does more than simply allow the Commission to conduct an effective review of proposed mergers. By establishing transparent, conservative standards for identifying competitive harm, the Commission has also allowed industry participants to evaluate contemplated transactions and to refrain
from proposing ones that would raise competitive concerns under the Commission's screening criteria.\textsuperscript{5} This, in turn, has greatly assisted the Commission in evaluating transactions that are proposed under Section 203 within the 180-day time-frame established by Congress.

EEI does not believe that it would be practical or advisable for the Commission to change its current reliance on the analysis of specified geographic and product markets and on the use of a prescribed methodology in conducting its Section 203 reviews. The departure from a transparent analytical approach to quantifying competitive harm would undermine the predictability of the review process and make it more difficult for companies to evaluate whether to go forward with potential transactions.

Although the Antitrust Agencies do follow a more flexible approach to merger review, the statutory missions of the Antitrust Agencies and the Commission differ, as do the processes and procedures employed in their respective reviews. Furthermore, the Commission’s review is governed by a strict statutory time limit that the Antitrust Agencies do not face. These differences mandate that the Commission employ review criteria and procedures that fit its statutory obligations, just as the Antitrust Agencies have adopted criteria and procedures suited to their own needs. Consequently, the Commission should continue to specify in detail, for the benefit of applicants, intervenors, and Commission staff alike, exactly which analyses should be performed and submitted with merger applications and the standards by which the Commission will evaluate the applications.

\textsuperscript{5} However, as discussed below, the screen employed by the Commission may have been too conservative and therefore may have prevented some companies from entering into mergers that would have proved beneficial.
On the other hand, EEI does believe that it would be appropriate for the Commission to adopt the revised Herfindahl-Hirschman Index ("HHI") thresholds set forth in the 2010 Guidelines. As explained in the guidelines, the revised thresholds are based on the Antitrust Agencies’ experience in evaluating mergers. The revised thresholds provide a reliable guidepost as to levels of concentration and changes in concentration that may raise concerns and warrant further analysis. This experience of the Antitrust Agencies indicates that adoption of these increased HHI thresholds by the Commission would continue to represent a conservative approach to analyzing proposed mergers. A failure to adopt the revised thresholds could result in many efficiency-enhancing mergers and acquisitions not being approved or, more likely, not even being brought to the Commission for its consideration.

EEI has reached similar conclusions with respect to use of the 2010 Guidelines in the context of the Commission's review of MBR applications under FPA Section 205. It is appropriate to rely on the increased HHI thresholds set forth in the 2010 Guidelines in reviewing MBR applications, as the Commission already does at least in part. However, due to differences in statutory missions, administrative procedures, and statutory time lines, it would not be practical for the Commission to adopt a more open-ended, less well-defined approach modeled on the 2010 Guidelines for reviewing MBR applications.

**COMMENTS**

I. **THE COMMISSION'S CURRENT SECTION 203 POLICY HAS BEEN SUCCESSFUL IN PREVENTING COMPETITIVELY HARMFUL Mergers AND OTHER TRANSACTIONS WHILE ALLOWING BENEFICIAL ONES TO GO FORWARD**

In its Merger Policy Statement, the Commission identified the specific factors that it will consider in determining whether a proposed transaction is consistent with the
public interest standard under FPA Section 203. The Commission also has provided unambiguous guidance both in its Merger Policy Statement and its subsequently-issued Part 33 Regulations as to: (a) how those factors should be addressed in a merger application, and (b) what commitments/demonstrations merger applicants must make in order to obtain the Commission's approval for the proposed transaction.

Since adopting its 1996 Merger Policy Statement, the Commission has reviewed and approved over 50 utility merger transactions, plus many more transfers of control over generation capacity. These transactions have reshaped the electric power industry and resulted in realized savings and efficiencies that ultimately have benefitted utility customers while assuring a safe and reliable electric power supply and the maintenance of competitive power markets. Moreover, under its current regulations, the Commission has undertaken those reviews in an expeditious and efficient manner.

At the same time, the Commission's current Section 203 Policy has effectively screened out potential mergers and asset transfers that could have had an adverse effect on competition. Although it is true that the Commission rarely rejects proposed mergers, its Section 203 Policy nevertheless deters potentially harmful mergers by ensuring that such transactions either are not pursued or are successfully mitigated with voluntary divestitures or other measures.

The Commission has achieved this result by spelling out in detail in its Part 33 Regulations the requirements for performing both horizontal and vertical Competitive Analysis Screens (“CAS”) that are required to be performed and included in an application for approval under FPA Section 203.\(^6\) By spelling out in detail the

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\(^6\) The requirements for conducting a horizontal CAS are spelled out in 18 C.F.R. § 33.3, and for conducting a vertical CAS in 18 C.F.R. § 33.4.
requirements for the competitive analyses the Commission uses to evaluate mergers, the Commission permits companies contemplating potential merger transactions to analyze, with a high level of certainty, the competitive effects, the likelihood of obtaining regulatory approval, and what mitigation (if any) may be required to obtain such approval.

Providing this detailed guidance has proved to be an exceedingly efficient and effective tool for carrying out the Commission's Section 203 Policy. Many potential transactions never get beyond the initial internal feasibility study phase simply because the companies involved can determine, in advance, that the transactions likely would not satisfy the Commission’s CAS and that mitigation required to satisfy the screens would not be cost effective. At the same time, because companies are able to determine ahead of time with a high degree of certainty that a contemplated potential merger or other transaction will satisfy the Commission's requirements, the Commission's Section 203 Policy encourages the pursuit of advantageous transactions that will not raise competitive concerns.

Thus, the specificity incorporated into the Commission’s current Section 203 Policy creates economic efficiencies by discouraging the filing of transactions that might not otherwise receive approval or that might require “further evaluation” by the Commission. Given that the cost of pursuing a merger typically runs in the tens of millions of dollars, not counting the disruption within the applicant companies, considerable time and resources are saved by a process that self-selects mergers that have a high likelihood of passing the Commission's competition review. The same is true at a scaled level of effect for other transactions.
At the same time, the Commission and its staff are spared from having to devote considerable time and resources to processing applications for transactions that have little likelihood of being approved. Prior to the Merger Policy Statement, the Commission was involved in several lengthy hearings to review proposed mergers (e.g., PacifiCorp,\textsuperscript{7} Southern California Edison/San Diego Gas & Electric,\textsuperscript{8} and Primegy\textsuperscript{9}) that required significant attention by the Commission and its staff. In the last ten years, however, the Commission's Section 203 Policy has allowed the Commission to apply a prompt and rigorous review to significant merger applications without the need to resort to lengthy hearings.

A corollary, but equally important, benefit of the Commission’s Section 203 Policy is the obligation of applicants to submit a completed competition analysis and all supporting data with their initial application. This allows the Commission staff and intervenors to have immediate access to all of the data necessary to evaluate the applicants' analysis and, in turn, to confirm or dispute the applicants’ results. Given the short statutory deadlines applicable to the Commission's review under Section 203, discussed in more detail below, the requirement that applicants submit this fully prepared analysis and supporting data with their initial applications is particularly important to an efficient and effective administrative process.

Consequently, EEI believes that the Commission should not make any radical changes to its current Section 203 Policy at this time. Rather, EEI believes the Commission should consider the experience gained by the Antitrust Agencies with


\textsuperscript{9} Wisconsin Electric Power Co., 79 FERC ¶ 61,158 (1997).
respect to HHI levels and then evaluate whether incremental changes to the Commission's current regulations could be advantageous. In so doing, the Commission should not alter the basic outlines of the current approach, which has many attendant benefits and has served the Commission well.

A. Response to Question No. 1: The Commission Should Continue to Focus Primarily on Analyzing Defined Markets Using a Prescribed Formula or Formulas

The Commission asks whether it should adopt the approach of the 2010 Guidelines and thereby decrease the emphasis its current policy places on defined markets and a prescribed formula for analyzing a merger’s potential competitive effects. NOI at P 15. EEI believes that the Commission should continue its current highly-specific and focused analytical approach, using methodologies and data specified in the Commission's Part 33 Regulations and presented by the applicants in their initial application.

Retaining such an approach, as opposed to moving to a less defined and more flexible analysis, is appropriate for at least three reasons: (1) a more flexible approach is not compatible with the procedures the Commission is required by law to follow in processing merger and other transaction applications under FPA Section 203; (2) a more flexible approach is not compatible with the 180-day statutory deadline applicable to the Commission’s review of the applications; and (3) the public interest is not otherwise served or enhanced by changing to a less structured, less predictable, more qualitative approach, such as that employed by the Antitrust Agencies.
1. The Commission's Procedures are Not Compatible With a Less Defined and Flexible Approach

The administrative procedures followed by the Antitrust Agencies in conducting their pre-merger review are very different from those used by the Commission to analyze proposed mergers and other transactions under FPA Section 203. These differences would make it extremely difficult for the Commission to adopt the flexible approach of the 2010 Guidelines.

Specifically, the Antitrust Agencies’ process is open-ended, non-public, non-adjudicatory, and off-the-record. A determination by the Antitrust Agencies to allow the Hart-Scott-Rodino ("HSR") Act waiting period to run or to provide for early termination is non-reviewable – the Antitrust Agencies need not issue a formal written order explaining or justifying such a decision. As a consequence, the Antitrust Agencies’ review is inherently flexible and unstructured.

Moreover, by its very nature, the process applicable to the Antitrust Agencies' review provides for an open give-and-take between the staff of the Antitrust Agencies, the merger applicants, and interested third parties. Because the Antitrust Agencies do not conduct an on-the-record adjudicatory review, none of their communications with the applicants or third parties raises ex parte concerns.

By contrast, the Commission's Section 203 review is governed by the requirements of the Administrative Procedure Act for on-the-record decisions. Thus, for example, after a merger application is filed, direct non-procedural communications between the Commission and applicants are forbidden in contested proceedings.\(^\text{10}\) Further, if the Commission requires additional data or analyses from the applicants,

\(^\text{10}\) 18 C.F.R. § 385.2201.
public notice of that fact must be provided. Any additional submissions made by applicants, in response to a Commission request, or upon their own volition, must be publicly noticed in the *Federal Register*, with an opportunity for any intervenor to submit comments. A final decision by the Commission must be (a) presented in a published order, (b) based on a reasoned evaluation of the record evidence, and (c) subject to judicial review. Consequently, in analyzing proposed mergers under FPA Section 203, it is impossible for the Commission to employ the same level of informality as do the Antitrust Agencies in their reviews.

Two examples that are typical of the HSR process conducted by the Antitrust Agencies illustrate this point:

➢ **Requests for Additional Analysis:**

- The Antitrust Agencies can communicate directly to the applicants seeking approval of a merger if there are any new or unexpected areas of concern. The applicants, in turn, can perform new analyses, present the results, and discuss the implications of those results directly with agency staff. Assuming the new analysis satisfies the identified concern, the merger can be permitted to go forward without any explanation or further justification.

- In contrast, if Commission staff determines that it is necessary to receive additional analyses from applicants seeking approval of a merger, the Commission must issue public notice of that fact, explain the underlying concern, and describe the specific analysis to be conducted. There would be restrictions on any give-and-take between Commission staff and the applicants to refine or target the information needed to resolve the inquiry. Additional guidance could be sought and provided only in the course of formal pleadings from the applicants before the Commission and in orders issued after a time-consuming process. Results of the additional analysis would be filed publicly by the applicants. Intervenors would be able to comment and, in turn, applicants likely would respond to those comments. Eventually, the Commission would issue a formal order on the requested approval of the merger, detailing its conclusions, and articulating how those conclusions are supported by the record.
Internal Analyses:

- During their review of a proposed merger, the Antitrust Agencies are free (a) to conduct any type of analysis, (b) to collect information from public sources or from third parties, including by way of subpoena, (c) to discuss those results with merger applicants and others, and (d) to base their ultimate conclusions on closely-held and often non-public analyses. In fact, during the review process, staff at the Antitrust Agencies often will discuss the results of their internal analyses with applicants in order to solicit constructive feedback which, in turn, can be incorporated into refining the agency’s analysis.

- Were the Commission staff to conduct an independent analysis of a proposed merger, a series of public notice and comment obligations would attach. An on-the-record description of the analysis and supporting data would have to be disclosed. Applicants and intervenors would have to be given the opportunity, in the course of a public proceeding, to test the applicable models and challenge the results. Parties would have the opportunity to submit written comments on the analysis. The Commission would be required to take those comments into account in issuing any order that uses, or declines to use, the analytical results.

These differences in processes make it much more difficult and time-consuming for the Commission to devise alternative analytical approaches after applicants have completed their initial filing.

2. The Commission's Statutory Deadlines are Not Compatible With a Less Defined and Flexible Approach

In 2005, Congress amended FPA Section 203 to impose a 180-day deadline for the Commission to issue final orders on proposed mergers and acquisitions. This deadline, which does not apply to the Antitrust Agencies’ review, makes it impractical for the Commission to adopt a less structured process. In contrast to the administrative procedures of the Commission, the Antitrust Agencies employ a two-step process in their

11 FPA Section 203(a)(5).
merger review. The initial HSR filing is comparatively short, and must be evaluated by agency staff within 30 days. The Antitrust Agencies issue a “second request” only in the event that the agency determines a more significant and detailed review is warranted. A sizeable majority of transactions reviewed by the Antitrust Agencies never reach this second request stage.

Once a second request is issued, however, the Antitrust Agencies' review process may continue for an indefinite period of time. The review is not concluded until 30 days after the merger applicants have substantially complied with the second request. Moreover, in practice, merger applicants and staff of the Antitrust Agencies frequently enter into "timing agreements" in electric utility merger cases. These agreements permit the second request time period to remain open for a specified period – during which time staff can continue to analyze the transaction and the merger applicants can respond on a rolling basis to the agency’s principal concerns regarding the merger.

By contrast, the 180-day time limit for Commission review of an application for approval of a Section 203 transaction was imposed by Congress precisely so that the Commission would conduct a focused and efficient review under FPA Section 203. Although Congress permitted the Commission to extend its review for an additional 180 days,12 this extra time is intended to be the exception and not the rule, as is evidenced by the fact that the Commission has extended its review only twice since the statutory deadlines were imposed in 2005.

Given the procedural requirements applicable to the Commission's review under FPA Section 203 described above, it would be virtually impossible for the Commission to

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12 *Id.*
conduct an unstructured review within the required statutory timeline for proposed
mergers or asset transfers involving more than a de minimis overlap of generation
capacity. Indeed, one-third of the statutory 180-day review period is consumed by the
60-day standard notice period during which time comments from intervenors are
submitted. After this notice period, only 120 days remains for the Commission to
evaluate comments and to issue an order requiring the submission of additional analyses,
for the Section 203 applicants to prepare such analyses, for intervenors to submit further
comments, and then for the Commission to issue a reasoned decision. It simply would
not be possible to accomplish all of these tasks in such a limited amount of time with a
less well defined analytic framework. The Commission thus would be forced to routinely
resort to the 180-day extension, which would be inconsistent with Congress’ intent.

3. **Because the Commission has Expertise in Electric Markets, It Can Provide Specific Instructions on How Markets Should Be Analyzed**

Under the HSR Act, the Antitrust Agencies are charged with reviewing mergers
in all industries. Each industry’s unique attributes make it impractical – and indeed
impossible – for the Antitrust Agencies to develop a set of detailed criteria that could
apply to all industries. The Antitrust Agencies must retain significant flexibility in their
merger guidelines in order to consider the specific factual considerations (such as market
definition, product definition, etc.) appropriate to evaluate competitive issues that arise
with regard to various different industries.

By contrast, the Commission has considerable technical expertise and
understanding of the electric utility industry and can bring that expertise to bear in
reviewing proposed transactions. As noted above, the Commission has reviewed over 50
utility mergers and many other transactions involving the transfer of control over
generation. The Commission also is intimately involved in addressing issues regarding market structure and the potential to exercise market power in the wholesale electric markets, and the Commission receives periodic reports on the state of the markets.

The Commission therefore is uniquely well-suited to determine, on a generic basis, (a) the manner in which market power in the electric industry should be evaluated, (b) how the relevant markets should be defined, (c) what products are relevant for consideration in the analysis, and (d) any and all other factors necessary to conduct an appropriate competitive analysis of proposed mergers or other transactions. Given that the Commission’s analysis applies solely to the electric industry, the Commission has far greater ability to adopt specific methodologies applicable to the electric industry and has less need to resort to the open-ended, flexible review procedures used by the Antitrust Agencies.

4. The Commission Should Retain its Current Approach of Specifying in Detail the Analyses that Should Be Included in a Completed Application

For the reasons discussed above, it is critical that the Commission continue to require merger and other transaction applications submitted for review under FPA Section 203 to include a complete and comprehensive analysis that is spelled out in detail in the Commission's Part 33 Regulations. In this way, the Commission and intervenors are presented at the outset with all of the data and analysis necessary for a full assessment of the proposed transaction. As noted, if a more flexible process were to be adopted, it would be impossible under the administrative procedures applicable to the Commission's review for the Commission to evaluate the application fully within the statutory time period.
To be sure, the Commission's Section 203 Policy allows applicants and intervenors in Section 203 proceedings to argue that other factors and issues should be considered and/or that other types of analysis should be performed. For example, the Commission has stated that intervenors are free to raise claims that monopsony power issues are raised by a particular merger,¹³ and that strategic bidding analyses based on computer simulations may be submitted as a supplement to the CAS analysis required under the Commission's Part 33 Regulations.¹⁴

EEI is not suggesting that the Commission change its Section 203 Policy in this regard. EEI believes that it is appropriate to consider such other issues and approaches in those instances where they are supported by the submission of sufficient evidence to indicate both that consideration of the alternative issue or analysis is appropriate and that it would cause the Commission to reach a different conclusion than would be reached under the Commission's primary analysis specified in its Part 33 Regulations.

Rather, EEI urges that the Commission retain its current policy of providing specific guidance to FPA Section 203 applicants of all filing requirements and of the procedures and criteria for the Commission's evaluation of Section 203 applications. The Commission's current policy not only deters prospective applicants from presenting to the Commission transactions that may inherently cause competitive concerns, but it also encourages companies considering beneficial merger and asset transfer arrangements that

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do not raise competitive concerns to move forward with confidence that the time and resources expended on the transaction will not be for naught.

**B. Response to Question 2: The Commission Should Adopt the Revised HHI Thresholds Contained in the Revised DOJ/FTC Guidelines**

The second question posed in the NOI is whether the Commission should revise its Section 203 Policy to reflect the new HHI quantitative market concentration thresholds adopted by the Antitrust Agencies in the 2010 Guidelines. EEI believes that the higher thresholds in the 2010 Guidelines more accurately describe the levels of market concentration and changes in concentration that may raise competitive concerns than the lower thresholds set out in the 1992 Guidelines. Therefore the Commission should adopt the revised HHI thresholds for use in its analysis of utility mergers and other transactions under Section 203.

The Commission should be confident that adopting the HHI thresholds set forth in the 2010 Guidelines will continue to result in a conservative approach to evaluating competitive effects of proposed transactions. As the Antitrust Agencies stated in implementing their revised guidelines, the increased HHI thresholds reflect the Antitrust Agencies’ actual experience over the years since the 1992 Guidelines were adopted. The Antitrust Agencies noted that the thresholds are useful in identifying proposed transactions that may raise concerns and warrant further scrutiny.

Furthermore, the Commission's continuing regulatory oversight over the electric industry adds a layer of protection that is not available to the Antitrust Agencies. Once a merger is completed, the Antitrust Agencies lose jurisdiction over the merging companies and must initiate legal actions against those companies to the extent that the agencies later determine that the companies are acting in an anticompetitive manner. Therefore,
by necessity, the standards applied by the Antitrust Agencies are very conservative in
nature.

By contrast, the Commission retains jurisdiction over the post-transaction
wholesale market activities by entities subject to its Section 203 review. Even after
completing a merger in the electric utility industry, the merged company will operate in
highly regulated and closely monitored settings. In many cases, the merged companies'
market activities will be subject to scrutiny from sophisticated and independent market
monitors, which the Commission has found to be an invaluable tool for mitigating the
potential for the exercise of market power.\textsuperscript{15} In regions where there are no organized
markets, sellers of power nevertheless must demonstrate that they lack market power in
order to sell at market-based rates, and if they cannot make such a demonstration they are
required to sell at regulated cost-based rates or to obtain authorization from the
Commission to use an alternative form of tailored mitigation.

The Antitrust Agencies have found the revised HHI thresholds to be conservative
even without such continuing oversight. The Commission should therefore feel
comfortable adopting the revised standards. To the extent that a proposed merger or
other transaction exceeds the revised Antitrust Agencies’ HHI thresholds, the transaction
should be treated the same as a proposed transaction that exceeds the thresholds under the
Commission's current policy, \textit{i.e.} the applicants would have the burden of demonstrating
that there are no adverse competitive impacts notwithstanding the screen violation.

\textsuperscript{15} In Order No. 697-A, the Commission adopted "a rebuttable presumption" that the existing
Commission-approved RTO/ISO mitigation is sufficient to address market power concerns with respect to
market-based rate authority in the RTO/ISO markets, including mitigation applicable to RTO/ISO
submarkets. \textit{Market-Based Rates For Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities}, 121 FERC ¶ 61,260 (2007), \textit{order on reh'g and clarification}, Order No. 697-A, FERC
II.  THE COMMISSION’S MARKET-BASED RATE REVIEW WOULD BENEFIT FROM A SIMILAR RESPONSE TO THE 2010 GUIDELINES

The Commission also solicited comments on whether it should incorporate the revised 2010 Guidelines into its Section 205 determinations involving MBR authorizations. As outlined below, EEI’s views on the applicability of the updated guidelines to the Commission’s Section 205 proceedings are similar to our views noted above with respect to the Commission’s Section 203 market power analysis.

In Order No. 697, the Commission established new indicative horizontal market power screens to govern its determinations in MBR cases. These screens were designed to identify sellers with the potential to exercise market power and whose market-based rates may no longer be just and reasonable, through the utilization of conservative, but administratively workable, procedures. If applicants for MBR authority fail either of these indicative screens, a rebuttable presumption of market power arises, which the applicants can rebut through the submission of alternative evidence such as historical sales data or the performance of a delivered price test (“DPT”) analysis based on market concentration thresholds adopted from the 1992 Guidelines.

EEI believes that the higher market concentration thresholds recently adopted by the Antitrust Agencies represent an accurate depiction of the potential to exercise generation market power in electricity markets. In fact, in the MBR context, the DPT already uses an HHI threshold of 2500, consistent with the 2010 Guidelines, and should

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16 NOI at P 21.

continue to do so. Thus, EEI would support the Commission updating its MBR regulations to reflect the higher HHI market concentration thresholds adopted by the Antitrust Agencies in the 2010 Guidelines, to the extent those higher thresholds are not already reflected in the MBR reviews, while also retaining the current flexibility the Commission employs in undertaking its reviews. The Commission also should consider increasing the market threshold for allowing MBR from 20% to 25%, consistent with this change in the HHI. Under the Commission’s guidelines, intervenors would still retain the option of submitting evidence that MBR sellers satisfying the guidelines could nonetheless exercise generation market power. However, in such cases, intervenors would bear the burden of proof and would have to present evidence to support their assertions.

For some of the same reasons noted above, the introduction of a less well-defined approach to evaluating market power issues modeled after the 2010 Guidelines would be inappropriate and infeasible in considering MBR applications under FPA Section 205. Sellers seeking MBR approval must file an initial application at the Commission, and to retain such approval the sellers must submit a “triennial review” application every subsequent three years. This process involves literally hundreds of applicants and extensive analyses, making a less well defined process infeasible.

Moreover, in its MBR reviews, the Commission is considering the potential for the exercise of generation market power by the applicant and its affiliates during a specific discrete time period, not an unlimited prospective change in that potential as a consequence of a proposed merger or acquisition. And during the three-year period covered by its MBR authorizations, the Commission receives change-of-status reports
from companies with MBR approval, identifying changes in factors relied on by the Commission in granting the approvals. Thus, it is not necessary to employ more open-ended techniques for analyzing how a potential combination could increase market power.

Further, there is no plausible way in which such issues could be adequately considered within the 60-day window wherein the Commission must act, absent suspension, under FPA section 205 for new MBR applications. While it is theoretically possible for the Commission to set an application for hearing, it is not practical to implement a procedure that requires hearings for most applications, given the large number of such applications that are submitted to the Commission. Instead, the Commission should continue with its current process that allows the Commission to identify the relatively few MBR applications that require additional consideration.

**CONCLUSION**

EEI supports the Commission's efforts to review periodically its Section 203 and Section 205 regulations, policies, and guidance, to ensure that the Commission’s approach to reviewing applications under these sections continues to reflect the results of pertinent economic research and changes in the electric power industry and market structure. We support the Commission adopting the higher HHI thresholds set out in the 2010 Guidelines in its FPA Section 203 and MBR reviews. However, we do not support the Commission adopting the more flexible, open-ended approach to reviewing horizontal market power set out in the 2010 Guidelines, for the reasons set out above. To the extent that the Commission determines that its competition review under the FPA
requires modification, the Commission should implement such changes in a way that avoids real harm to a process that has shown itself to work effectively to the benefit of the industry, consumers, and the Commission itself for over a decade.

Respectfully submitted,

- signature –

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May 23, 2011
2011 EBA Mid-Year Meeting
Electric Industry Consolidation
and Merger Policy

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State Commission Responses

Jurisdiction and Scope of Review

- PSCs will and should assert jurisdiction.
- PSC review tends to be broad under various public interest standards.
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IN THE MATTER OF THE CURRENT AND FUTURE FINANCIAL CONDITION OF BALTIMORE GAS AND ELECTRIC COMPANY

ORDER NO. 82986; CASE NO. 9173 PHASE II

Maryland Public Service Commission

2009 Md. PSC LEXIS 59; 277 P.U.R.4th 365

October 30, 2009

PANEL: [*1] Douglas R. M. Nazarian; Harold D. Williams; Susanne Brogan; Lawrence Brenner, Commissioners

OPINION: To: The Parties of Record and Interested Persons

I. INTRODUCTION AND EXECUTIVE SUMMARY

In this Order, the Public Service Commission n1 ("Commission") grants E.D.F. International S.A. and EDF Development, Inc.'s n2 application for approval of a proposed Transaction n3 with Constellation Energy Group, Inc. ("CEG"), subject to conditions we define below. With these conditions, most of which adopt or track the Companies' n4 proposals, the Transaction will satisfy Public Utility Companies Article ("PUC") § 6-105(g), which requires us to find it "consistent with the public interest, convenience and necessity, including benefits and no harm to consumers." n5

n1 Commissioner Goldsmith has taken no part in the hearings or deliberations in this case or in the preparation of this Order.

n2 E.D.F. International S.A. and EDF Development, Inc. are wholly-owned subsidiaries of Electricite de France International, S.A. . Unless otherwise noted, the shorthand "EDF" is used to refer generally to the EDF family of companies and any specific EDF entity that may be involved in a particular element of the proposed Transaction.

[*2]

n3 We discuss the precise terms of the transaction before us (the "Transaction") at pp. 19-24 below.

n4 We use the shorthand "the Companies" to refer collectively to CEG and EDF.

n5 PUC § 6-105(g)(3). See also id. (3)(ii) ("The Commission may condition an order authorizing the acquisition on the applicant's satisfactory performance or adherence to specific requirements."). Unless otherwise noted, citations to statutes refer to the PUC Article.

We ground our ruling on two fundamental decisions. First, it is not enough for the Companies to prove that the
Transaction is "consistent with the public interest convenience and necessity" -- they also must demonstrate that the Transaction will offer "benefits and no harm to consumers." For the phrase "benefits ...to consumers" to have any meaning, the ratepayers of Baltimore Gas and Electric Company ("BGE") must receive benefits directly, in their capacity as BGE customers, not just their share of the Transaction's impact on the public at large. The proposed new nuclear generation [*3] station at Calvert Cliffs ("Calvert Cliffs 3") is, in our view, too contingent, to provide "benefits...to consumers" under § 6-105(g). The same is true to CEG's commitment to provide (at no cost to BGE) access to a site for construction of a new electric generation station by BGE. The other potentially positive results of the Transaction, including the post-closing tax payment to the Maryland Treasury, flow to ratepayers only in their capacity as citizens. We have not ignored the broader value, and thus the public interest, in the good things that the Transaction could accomplish for CEG and the State as a whole -- those opportunities provide the support for our broader finding that the Transaction is "consistent with the public interest, convenience and necessity" with appropriate conditions. But the law requires something more, and the Transaction as proposed does not deliver it.

Accordingly, we condition approval of this Transaction on a reasonable, one-time, per-customer distribution rate credit to BGE's residential ratepayers of $110.5 million. The rebate is designed to be as neutral financially to the Companies as possible, and to bring the Transaction in line with the statute [*4] without diminishing the Transaction's positive impact on CEG's balance sheet. We are comfortable that the impact of the rebate to the Companies falls well within the range that CEG's witnesses have called "immaterial" n6 because we have tied it to amounts EDF has agreed at different times to pay above and beyond the $4.5 billion purchase price -- the $20 million EDF agreed to pay to build a visitor center at Calvert Cliffs, the $36 million EDF agreed to contribute to CEG's charitable foundation, the $32 million EDF had agreed to pay into CEG's long-term incentive plan -- and added the $22.5 million CEG has offered to pay to ratepayers if we do not further limit BGE's next distribution rate case. n7 The total $110.5 million rebate will provide a credit of approximately $100 for each BGE residential customer, and BGE should implement the credit before the end of March 2010, so that the rebate offsets winter heating bills. This condition should not restrict EDF or CEG from building a visitor center or funding CEG's foundation or both, since these projects will cost a small fraction of the more than $1 billion CEG will have after retiring debt, not to mention the $1.2 [*5] - $1.4 billion in federal and state tax savings the Companies will realize after closing. n8

n6 Transcript of Phase II Hearing, October 14, 2009 ("Oct. 14 Tr.") at 2601-2602:

   Chairman Nazarian: When you say material, Mr. Collins, . . .what is the order of magnitude in terms of dollars that you're considering material or immaterial?

   Mr. Collins: [referring to immaterial post-closing price adjustments] In the tens of millions of dollars and not in the hundreds of millions of dollars.

n7 See Post-Hearing Brief of Constellation Energy Group, Inc. and Baltimore Gas and Electric Co. at 11.

n8 Oct. 14 Tr. at 2464 (Panel Testimony of John Morris, Michael Wallace and John Collins).

Second, we are more concerned now than we were at the end of Phase I about the availability of capital to fund the operations and solidify the balance sheet of BGE. CEG's real-life, near-death experience in September 2008 demonstrated all too vividly how vulnerable BGE is if, and when, things go badly for CEG. This Phase has [*6] confirmed, as we found in Phase I, n9 that the new business relationship between CEG and EDF will permit EDF to "exercise ...substantial influence over the policies and actions" of BGE and will expose BGE and its ratepayers to additional risks. The Transaction increases the competition for capital within CEG and creates new risks to BGE's credit rating, and the Companies' increasing commitment to nuclear energy only raises the stakes.
Because the statute requires us to find that the Transaction causes "no harm to consumers" before we can approve it, we condition our approval on a series of measures that will protect BGE from future risks and strengthen its financial condition:

(a) Capital infusion. CEG shall invest $250 million in cash in BGE between now and June 30, 2010;

(b) Dividend restriction. Until further order of the Commission, BGE may not pay dividends to CEG if BGE's equity level after the dividend payment would fall below [*7] 48%, and may not pay dividends under any circumstances if BGE's credit rating falls below investment grade, as determined by any two of the three major credit rating agencies;

(c) Rate case timing. BGE may file its next electric distribution rate case beginning in January 2010, may not file a subsequent electric distribution rate case until January 2011, and the timing of any gas distribution rate filing will occur no earlier than the electric cases; and

(d) Ring-fencing. Immediately after close of the Transaction, CEG shall begin to implement a detailed series of measures designed to create distance between BGE and CEG for purposes of bankruptcy protection and credit rating separation, including prohibiting BGE from participating in CEG's cash pool. At the December 1, 2009 status conference, the Companies shall provide a timeline for implementing the ring-fencing measures.

This list here is not exhaustive -- see also pp. 40-53 below for the details and analysis.

We use ring-fencing to generally describe conditions designed to create legal distance between CEG and BGE, so that BGE is protected from a CEG bankruptcy and BGE's credit rating is separated from CEG's.

These conditions not only will protect BGE against financial catastrophe at the hands of its parent, but will strengthen BGE in ways that will yield more for ratepayers in the long term than any rebate. By infusing new capital into BGE, CEG invests in BGE, not just in the joint venture and Calvert Cliffs 3. New capital may reduce BGE's cost of and need for borrowing, and, we hope, improves BGE's credit rating. These conditions not only should provide BGE with the additional capital necessary to provide safe and reliable service at just and reasonable rates, but should enhance its financial stability. As with any prudent investment, the returns to ratepayers may not be flashy or immediate, but then again, "[s]omeone's sitting in the shade today because someone planted a tree a long time ago."
inform the Commission in writing by no later than November 6, 2009, whether they plan to close the Transaction and, if so, when. With these conditions in place, we find no need to order further proceedings relating to this Transaction, except that we direct the Companies to appear for a conference on December 1, 2009, at 10:00 AM to report on the status of the Transaction and their progress toward implementing the conditions set forth in this Order.

One last point bears a brief mention up front. Despite our careful efforts in the Phase I Order to keep this case focused on the issues the Transaction actually presents, some have actively conflated the already-complicated questions before us with other issues, most notably, the construction (or not) of Calvert Cliffs 3. As we explain, the decision to build Calvert Cliffs 3, and the fate of any impact to our State from that project, lies in the Companies’ hands at this point, not ours, and depends on a great many pending and uncertain decisions that are the responsibility of others.

n13 We are equally aware that others would have us use this case as a vehicle to address broader, and understandable, public concerns about nuclear power, executive compensation, corporate behavior or the electricity markets.

Tempting as it might seem, it would be inappropriate for us to overreach in any direction. We have focused, as we must, entirely on BGE and the impact of this Transaction on that utility and its ratepayers -- not because we are disinterested in addressing or unwilling to solve other problems, but because the law prescribes a specific task for us here. It is unfortunate, though, if public officials, unions, churches, Chambers of Commerce, business owners, the press and, most of all, the Companies' employees have been (mis)led to believe that our decision approving this Transaction guarantees that Calvert Cliffs 3 will be built.

II. BACKGROUND

A. The Phase II Proceedings

1. EDF’s Application

This Order resolves Phase II of this proceeding and, in light of our findings and conclusions, resolves the issues presented by EDF’s Application. We initiated this Phase after finding, at the conclusion of Phase I, that EDF would "acquire, directly or indirectly, the power to exercise substantial influence over the policies and actions of BGE" after the Transaction closed. n14 Our Phase I Order addressed the "substantial influence" question at length, and we presume familiarity with that Order for purposes of this one.

n14 Phase I Order at 34.

Our Phase I Order directed the Companies and other parties to appear for a status conference on June 17, 2009, n15 since § 6-105(g) then required us to "examine and investigate each application received," and "undertake any proceedings necessary or convenient [*12] to review the application in accordance with Title 3 of the [Public Utility Companies] article." n16 After hearing from the parties that day, the Commission established a schedule for discovery, testimony and hearings designed specifically to complete this Phase by the original Transaction closing date of September 17, 2009. As the necessary first step, EDF filed its Application on June 19, 2009, asking formally for approval under § 6-105 to proceed with the Transaction.
n15 Id. at 35. Perhaps not surprisingly, the Companies were displeased with the Phase I Order, and asked the Circuit Court for Baltimore City to enjoin Phase II. Constellation Energy Group, Inc. et al. v. Maryland Public Service Comm’n et al., Case No. 24-C-09-003720 (Circuit Court for Baltimore City). The Circuit Court dismissed the Companies’ complaint on July 2, 2009, holding that their claims were unripe in light of our decision to schedule and convene Phase II on an expedited basis. Id. The Companies appealed this decision to the Maryland Court of Special Appeals and that appeal is pending.

n16 PUC §§ 6-105(g)(1) and (2).

[*13]

The Application set into motion an intensive litigation process that has demanded extreme effort and endurance from everyone. The timing of the Transaction has required us, and everyone, to begin and finish in a little over four months a case that normally would consume the full six- to seven-and-half months the statute allows. n17 To accomplish this, we truncated every deadline, expedited every procedure, filled in every empty time slot, and expected the lawyers and parties to come as early or stay as late as it took to get the work done. To be sure, the case was fought hard and featured some tense and challenging moments. But it was fought well, and we would be remiss if we failed to acknowledge that everyone involved in the case met our high expectations and conducted him- or herself with professionalism. We do not take this for granted, and the Commission thanks all of the parties, witnesses, lawyers, paralegals, assistants, and everyone on all sides for making it possible for us to complete a thorough public interest review of this Transaction on this hyper-accelerated schedule.

n17 PUC § 6-105(g)(6).

[*14]

2. Discovery and Scheduling

CEG and BGE filed supporting testimony on June 24, 2009, and the parties n18 undertook extensive discovery, including hundreds of data requests, thousands of pages of document production and numerous depositions. Not surprisingly, the overwhelming bulk of the discovery was directed by Staff, OPC and the State/MEA to the Companies-- after all, they possessed the overwhelming bulk of the relevant information. And as might be expected given the volume and complexity of the information at issue, there were a number of disputes regarding the scope and terms of the requests and productions, including applicable privileges. Early on in the life of this case, we created an expedited process through which the parties could raise, and we could resolve, discovery disputes. n19 The parties all availed themselves of these procedures, and the Commission held at least four lengthy discovery conferences.

n18 The Applicants are E.D.F. International S.A. and EDF Development, Inc. The other parties (not all of whom participated in all aspects of the case) include: Constellation Energy Group, Inc. ("CEG"); Baltimore Gas and Electric Company ("BGE"); the State of Maryland and Maryland Energy Administration ("State/MEA"); the Technical Staff of the Maryland Public Service Commission ("Staff"); Office of People's Counsel ("OPC"); Mayor and City Council of Baltimore; Maria Allwine; International Brotherhood of Electrical Workers; Sun Edison LLC; Nuclear Information and Resource Service, Beyond Nuclear, Public Citizen, Maryland Public Interest Research Group, Maryland ACORN, CPV Maryland LLC; Chris Bush; Maryland Tax Education Foundation; Severstal Sparrows Point LLC; Maryland Alliance for Fair Competition; Air Conditioning Contractors of Maryland; Central Maryland Chapter; the National Railroad Passenger Corporation ("Amtrak"); and the United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada, AFL-CIO.
Despite the good faith and hard work of all of the parties -- there were disagreements, to be sure, but all fell within the range of aggressive but fair litigation positions -- we decided on July 30, 2009 that a proper, thorough public interest review of the Transaction required more time than we had allotted:

Over the past several weeks, the Commission has held four discovery conferences for the purpose of hearing and resolving discovery disputes raised by Staff, the State/MEA, OPC, and Amtrak against CEG, BGE and EDF. Although the disputes have been numerous, and both sides have "won" at different times, the Commission recognizes that all of the parties have worked extremely hard to conduct discovery under the current, expedited procedural schedule, and the Commission commends them for their efforts. That said, the Commission is concerned that the issues before it in this case are broad, deep and complex. The reality of litigation is that well-founded discovery disputes consume precious days and weeks, even when heard and resolved quickly. In the context of this highly accelerated schedule, the time lost to discovery disputes has left an untenably short time for the development of a full factual and analytical record on these complicated issues.

The Commission is aware and mindful that CEG and EDF want to close the transaction by September 17, 2009, and the Commission has made every effort to complete the public interest review with that deadline in mind. But the Commission cannot and will not compromise the quality of the public interest review of this transaction, and the Commission finds that the public interest in a thorough review outweighs the companies' understandable desire to close by September 17th. Neither the parties nor the public should read anything more into this ruling beyond a finding that a proper public interest review requires more time than the current schedule permits. The Commission makes no findings or rulings, and foreshadows nothing, regarding the merits of the transaction, the likelihood of approval, or anything else at this point.

Under the initial procedural schedule, hearings were to start on August 19, 2009. Our Order of July 30, 2009 extended the schedule to provide additional time for reply and rebuttal testimony and allow post-reply discovery, and we moved the hearings to the week of September 14, 2009. That schedule held and, as detailed below, the parties filed thousands of pages of direct, rebuttal and sur-rebuttal testimony from 22 different witnesses.

3. The Issues and Witnesses

We will not attempt to recount the witness testimony in detail (we will discuss the testimony and exhibits as necessary in our analysis), but offer a summary of the pre-filed testimony that highlights the key issues and witnesses.
The Companies' direct testimony argued that the Transaction met the statutory standard on its face and that we should approve it without conditions. Mr. Morris of EDF, Mr. Wallace of CEG and Mr. DeFontes of BGE each described elements of the Transaction and claimed that consumers would benefit from tax payments CEG would make to the State at closing, and from the economic development impact from the future development of Calvert Cliffs 3, the construction of a visitor center, EDF's contribution to CEG's charitable foundation, and the relocation of EDF's United States headquarters to Maryland. n21 The Company witnesses contended as well that the Transaction posed no risk of harm to consumers, n22 given their Phase I view that EDF would not acquire the power to exercise "substantial influence."

n21 Direct Testimony of Michael Wallace ("Wallace Direct Testimony") at 12-13; Direct Testimony of Kenneth DeFontes ("DeFontes Direct Testimony"), at 4-8; Direct Testimony of John Morris ("Morris Direct Testimony") at 14-15, 19.

n22 Wallace Direct Testimony at 13-15; DeFontes Direct Testimony at 8-9, 12-13; Morris Direct Testimony at 15-18.

[*19]

The reply testimony of other parties opposed the Companies' view that the Transaction met the statutory standard without conditions -- although, importantly, no witness filed testimony contending that we should deny the Application outright. n23 Each of the reply witnesses n24 took issue with the Companies' analyses of the Transaction's relative benefits and potential harms. The State/MEA, through Yale Law School Professor Alan Schwartz, argued that the Companies had the legal definition of "benefits ...to consumers" wrong, and that § 6-105(g)(3) could be satisfied only by benefits received directly by BGE ratepayers. n25 Other witnesses challenged the value of the various benefits posited by the Company. The most notable example, Staff witness Julia Frayer, offered a sophisticated economic analysis of the proffered benefits of the proposed Calvert Cliffs 3 plant, discounted by her analysis of the likelihood that the plant ever would be built. n26

n23 The Brief of the Nuclear Information Resource Service, Beyond Nuclear, Public Citizen, the Maryland Public Interest Research Group and Maryland ACORN does argue that we should deny the Application outright, but grounds that position largely in the mistaken premise that BGE ratepayers are exposed to the cost of (and cost overruns from) constructing Calvert Cliffs 3. See Docket Entry No. 210.

n24 An exception would be the two reply witnesses from Amtrak, Messrs. Forczek and Faryniarz, who asked that we impose conditions protecting Amtrak's ability to purchase specialized power from a specific CEG facility, which was included in the list of non-nuclear assets that CEG could put to EDF under the put option. See Reply Testimony of Stanley R. Forczek at 31-32, and Reply Testimony of Stan Faryniarz at 22-23. On October 23, however, Amtrak filed a letter stating that it had undertaken further discussions with CEG and withdrew its request that we impose Amtrak-related conditions in this case. Accordingly, we consider Amtrak's requests no further. See Docket Entry No. 209.

n25 Reply Testimony of Alan Schwartz ("Schwartz Reply Testimony") at 10-11.

n26 Reply Testimony of Julia Frayer ("Frayer Reply Testimony") at 24-51.

Each of the parties proposed conditions that, in their view, would bring the Transaction in line with their view of the statute. n27 Professor Schwartz argued that we should condition approval on the requirements that CEG infuse $
304-465 million into BGE, [*21] n28 that we require BGE to achieve and maintain an equity level in the 46-48% range, n29 and that we impose ring-fencing and corporate governance conditions that would give BGE greater protection against and independence from CEG. n30 OPC, through Daniel Lawton, generally agreed, n31 as did Commission Staff, through Howard Lubow, particularly with regard to the need for a cash infusion, ring-fencing measures and the need for greater corporate independence for BGE. n32 Jeffrey Hooke, testifying for the Maryland Tax Education Foundation, argued that we should order CEG to provide 100% of BGE's Standard Offer Service electricity on a cost-of-service basis, n33 on the theory that CEG would still be ahead financially compared to a scenario in which we disapproved this Transaction. n34

n27 We have considered each of the myriad of proposals carefully in our deliberative process, but we cannot write separately about all of them. Accordingly, only those conditions specifically identified as conditions required for closing are being imposed upon this Transaction; all others are appreciated, but rejected. [*22]

n28 Schwartz Reply Testimony at 35.
n29 Id. at 30.
n30 Id. at 39-45.
n31 Reply Testimony of Daniel J. Lawton ("Lawton Reply Testimony") at 51-52.
n32 Reply Panel Testimony Howard E. Lubow and Dr. J. Robert Malko ("Lubow and Malko Reply Testimony") at 5.
n33 Reply Testimony of Jeff Hooke ("Hooke Reply Testimony") at 17-18.
n34 Id.; See also Transcript of Phase II Hearing, Sept. 18, 2009 ("Sept. 18 Tr.") at 1859-1860.

On rebuttal, the Companies took a slightly different tack. Although they adhered to their original position that the Transaction meets the § 6-105 standard, n35 and also sought to refute the opponents' arguments regarding possible harms and missing benefits, n36 they offered a series of conditions that, according to senior CEG executives John Collins and Michael Wallace, CEG management would recommend to its Board of Directors. n37 Among other things, Messrs. Collins and Wallace offered that CEG would infuse "up to $ 250 million" in cash into BGE to achieve an equity level within a range of 40-44% (they contended that BGE's then-current [*23] level was approximately 42%). n38 They testified that BGE would agree not to file a distribution rate case until January 2010, and that BGE would limit itself to a maximum distribution rate increase of 2.5%. n39 They offered that BGE would not pay dividends to CEG through calendar year 2009 (a promise they had made previously) n40 and would not pay dividends in the future if BGE's equity level fell below the number we set (between 40-44%) or if two of three credit rating agencies dropped BGE's bond rating below investment grade (currently BGE maintains an investment-grade rating). n41 In addition, the Companies offered to implement a ring-fencing plan sponsored by investment banker Charles Atkins that was designed, in his view, to protect BGE from bankruptcy and provide credit rating separation from CEG. n42

n35 Rebuttal Testimony of Michael J. Wallace and John R. Collins ("Wallace and Collins Rebuttal Testimony") at 3-6; Rebuttal Testimony of Anirban Basu ("Basu Rebuttal Testimony") at 3-9; Rebuttal Testimony of William Chambers ("Chambers Rebuttal Testimony") at 3; Rebuttal Testimony of Michael M. Schnitzer ("Schnitzer Rebuttal Testimony") at 3-5; 13-19.

[*24]

n36 Wallace and Collins Rebuttal Testimony at 6-9; Chambers Rebuttal Testimony at 3-4; Schnitzer Rebuttal
Testimony at 19-27.
n37 Wallace and Collins Rebuttal Testimony at 34-35; Oct. 14 Tr. at 2469-2470 (Panel Testimony of John Morris, Michael Wallace and John Collins).
n38 Wallace and Collins Rebuttal Testimony at 13.
n39 Id. at 14. This 2.5% limitation was predicated on their offer of 40-44% minimum equity level and contained the caveat that the actual limit would be higher if the Commission imposes a higher equity level. Id. The witnesses also argued that this offer improved upon the 5% limitation on the first rate case to which CEG and BGE agreed in connection with the 2008 Settlement that they reached with the State and the Commission. Id. at 13-14.
n40 Phase I Order at 28-29.
n41 Wallace and Collins Rebuttal Testimony at 35.
n42 Id. at 35; Rebuttal Testimony of Charles N. Atkins ("Atkins Rebuttal Testimony") at 12-19.

4. The Evidentiary and Evening Hearings

After receiving and reviewing the three waves of testimony, we held comprehensive [*25] evidentiary hearings. Over the course of six days, the Commission presided over more than 70 hours of hearings that generated over 2,500 transcript pages. Hearing days began as early as 8:00 AM and, save for Rosh Hashanah, went until 10:00 PM or later most nights. n43 Although we had, of course, received and reviewed the pre-filed testimony at each phase, n44 we allowed all of the parties to cross-examine each of the others' witnesses at length, with very little temporal or substantive limitation, then questioned witnesses ourselves. We also considered carefully OPC's and the State/MEA's motion to exclude the testimony of Staff witness Julia Frayer and Company witness Michael Schnitzer on the ground that their efforts to quantify the societal benefits from Calvert Cliffs 3 were grounded in inherently unreliable ("junk science") methods. n45 We ultimately denied the motion because, in the course of reviewing the testimony and ruling on the motion, we knew the witnesses' positions and already were in a position to accord the challenged testimony (or any other) the weight we felt it deserved. As a general rule, we sought throughout the hearings to maintain a courtroom-caliber standard [*26] of legal and evidentiary rigor, but erred whenever necessary on the side of allowing more rather than less information or argument to come in.

n43 During the hearings, the Companies also amended the Transaction documents to extend the closing deadline from September 17, 2009 until October 30, 2009.

n44 We also permitted the parties to submit sur-rebuttal testimony during the hearing (which was admitted without objection). Transcript of Phase II Hearing, Sept. 21, 2009 ("Sept. 21 Tr.") at 1874.

n45 OPC's Motion to Strike Portions of the Reply Testimony of Staff Witness Julia Frayer (Sept. 11, 2009); State/MEA's Motion In Limine to Exclude Testimony of Julia Frayer and Michael M. Schnitzer (Sept. 11, 2009).

Although originally scheduled to conclude by September 18, 2009, we added a sixth hearing day, September 21, 2009, in order to permit the parties and the Commission to develop a full record. In addition, we scheduled and held evening public comment hearings throughout BGE's service territory, in Annapolis, [*27] Baltimore City and Bel Air, for the purpose of providing the opportunity for public comment on the proposed transaction. n46 The Commission stayed at each of those hearings until everyone who wished to speak had a chance to do so, and we heard from more than 150 people altogether. n47

n46 Case No. 9173, Notice of Hearings for Public Comment, Docket Entry No. 147 (August 10, 2009).

n47 It did not escape our notice that the Companies organized and orchestrated public hearing commentary from
dozens of individuals and organizations, including public officials, chambers of commerce, business owners, non-profit organizations and their employees. It is, of course, the right of the Companies and of all individuals to be heard at these hearings, and we want and need to hear all points of view. To the extent, however, that organized participation in our evening hearings by parties to the case deters or overwhelms individual citizen participation, those tactics defeat the purpose of the evening hearing and we discourage them.

[*28]

At the end of the hearing day on September 21, 2009, we thought we were finished, save for briefing and deliberations. But just as the proceedings were breaking, the parties raised the issue of whether several recently executed revised Transaction documents n48 materially altered the terms of the Transaction or, more to the point, required further proceedings to ensure that we would be reviewing the transactions the Companies intended to close.

n48 Although the Transaction documents contemplated that the Companies could continue to negotiate the terms of the Transaction and the Companies had provided revised documents to the parties earlier in discovery, the revised Transaction documents were not filed with the Commission or otherwise provided to the Commission until later on September 21, 2009.

n49 By statute, the applicant is required to file the revised documents with the Commission, see PUC § 6-105(f)(6).

5. Supplemental Testimony and Hearings [*29]

We directed CEG and EDF to file the executed documents with the Commission by the close of business that day, September 21, 2009, n50 and scheduled a status conference for September 25, 2009, to determine whether the parties required additional testimony or discovery with respect to the revised documents. At that status conference, the Commission set an additional hearing date of September 29, 2009, to hear testimony relating to the revised documents. After that hearing, which included approximately six hours of live testimony from a panel of Company witnesses, we directed the parties to file (by close of business on October 1, 2009) papers, in the nature of the summary judgment affidavits required by Federal Rule of Civil Procedure 56(f), identifying any issues that required further discovery or proceedings, and to appear for another status conference on October 2, 2009.

n50 See Docket Entry No. 178.

The October 1 filings and October 2 status conference revealed [*30] a genuine issue of fact as to whether the revised terms of the transaction altered our public interest analysis, particularly with regard to revisions designed to achieve tax savings and to a complex series of power purchase agreements among Constellation Energy Nuclear Group, LLC ("CENG"), CEG and EDF meant to replace the power marketing arrangement agreed to by the Companies in December 2008. Accordingly, we granted the State/MEA's, OPC's and Staff's request to submit additional testimony, ordered new testimony to be filed by noon on October 13, 2009, and held another full day of hearings -- beginning with the new State/MEA, OPC and Staff witnesses, then live Company rejoinder testimony -- on October 14, 2009.

Three parties filed additional testimony on October 13, 2009 and presented witnesses on October 14, 2009. First, OPC witness William D’Onofrio testified that the Companies had overstated the extent of the long-term net tax benefits the State of Maryland would receive in connection with the Transaction -- the correct, net present value, in his view,
was approximately $42 million, not the $129 million the Companies had posited. n51 Second, State/MEA witness Anil Suri [*31] testified that the new power purchase arrangements among CEG, Constellation Energy Commodities Group, Inc. ("CECG") and EDF for the output of the CENG plants exposed CEG to an additional $700 million of liquidity exposure than the original power marketing arrangement. n52 Third, Staff witness Howard Lubow opined that the Companies had revised the Transaction in non-trivial ways, but that the conditions he had recommended in previous rounds of testimony would provide appropriate protection for BGE. n53 The Companies followed with a panel of Messrs. Morris, Collins and Wallace, who reiterated the Companies' views that the Transaction had not changed in a material way and that the Companies' proposed conditions appropriately protected BGE. n54 In response to questions from the Commission about changes to the purchase price, Mr. Collins acknowledged that the purchase price EDF would pay had changed somewhat, and could change further at closing according to certain adjustments the parties had negotiated. He characterized these adjustments -- which could reduce the final purchase price by "tens of millions of dollars," perhaps as much as $50 million -- as "immaterial." n55


[*32]

n52 Testimony of Anil K. Suri ("Suri Testimony") at 5.
n53 Oct. 14 Tr. at 2419-2420 (Howard Lubow).
n54 Id. at 2449-2620 (Panel Testimony of John Morris, Michael Wallace and John Collins).
n55 Id. at 2602.

At the close of the October 14 hearing, we set a briefing deadline of noon on October 26, 2009, and directed CEG and BGE to answer three further questions, to the extent the answers were not already in the record:

1. What is BGE's current equity level?

2. How much of an equity infusion would be required to raise BGE's equity level to 44% by June 30, 2010?

3. Assuming a $250 million equity infusion by June 2010, what would BGE's equity level be?

CEG and BGE answered these questions on October 23, 2009, stating, with some qualifications, that its current equity level was 42.9%, that "the Company expects it will not need an equity infusion in June 2010 to achieve a 44% equity level as computed using the traditional Maryland rate-making methodology," n56 and that BGE's equity level would be 48% after a $250 million equity infusion. We received the parties' briefs [*33] as ordered, and decide this case based on the full record developed in both Phases of this case.

n56 Letter from Deborah Jennings, on behalf of CEG and BGE, to the Commission, dated October 23, 2009, Docket Entry No. 208. CEG and BGE requested confidential treatment for its answers, but we find that the portions of the answers that we reference here and elsewhere in this Order do not reveal any confidential, proprietary or competitively sensitive information.

B. The Transaction
When the Companies executed their original documents in December 2008, n57 they agreed to a Transaction that featured a number of complicated moving parts:

(i) EDF agreed to pay $1 billion at signing (credited against the overall purchase price) and receive 10,000 shares of Series B Preferred Stock of CEG; n58

(ii) an EDF affiliate would acquire a 49.99% share of Constellation Energy Nuclear Group, LLC ("CENG"), the holding company subsidiary that owns the nuclear assets, including Calvert Cliffs Units 1 and 2, in exchange for [*34] $4.5 billion in cash (including the $1 billion paid at signing); n59

(iii) EDF agreed to provide liquidity support to CEG in various ways, most notably an asset put option pursuant to which CEG could sell certain non-nuclear generating assets having an aggregate value of up to $2 billion to an EDF affiliate; n60

(iv) EDF would obtain, at closing, the right to nominate one director to CEG's Board of Directors; n61 and

(v) CENG would assume $700 million in underwater hedges on its balance sheet, and Constellation Energy Commodities Group ("CECG") would enter into a marketing relationship with CENG. n62

n57 See Phase I Order at 7-10. We will not repeat here the history of the Transaction from its inception through the Phase I Order, but refer the reader instead to that discussion.

n58 EDF Application, Docket Entry No. 106, at 5.

n59 Id. at 6.

n60 Id. at 7.

n61 Id. at 7.

n62 Master Put Option and Membership Interest Purchase Agreement § 6.21 (subsequently deleted). In an effort to avoid revealing competitively sensitive information, we have left purposely vague our descriptions here, and throughout this Order, of the various proposed marketing and power purchase arrangements among CENG, CECG and EDF. The impact of these arrangements on CEG and, derivatively, on BGE has mattered to our analysis, as we explain below, but it is not necessary to detail the precise arrangements in this Order.

[*35]

As we reached the end of the hearings in this Phase II, the Companies for the first time offered to file with the Commission revised Transaction documents, although they had circulated drafts of the Transaction documents to the parties on the eve of the Phase II hearings. n63 The fact that they had continued to refine the Transaction did not surprise or trouble us in itself. We were, however, frustrated by their decision to file these revisions with us only after we had devoted six days of hearings, not to mention the pre-hearing proceedings, to the Transaction in its original form. n64


n64 Transcript of Phase II Hearing (October 2, 2009) ("Oct. 2 Tr.") at 70-71:

Chairman Nazarian: I'm saying we would have liked to have a hearing about the actual bloody deal as opposed to the hypothetical one that you're in the middle of changing. When we're sitting
here hour after hour until midnight with witnesses who are testifying about the special matters provisions and everything else, and you’re sitting there knowing that it’s going to be different, and then you hand it out ... How are we supposed to do that with a straight face [and] any intellectual honesty to the people of this state?

[*36]

The Companies are, of course, free to enter into whatever agreements they think appropriate. But after our Phase I Order, they knew full well (even if they disagreed) that they were not authorized under Maryland law to close this Transaction without our approval, and not free to close a Transaction that varies from whatever Transaction and conditions we ultimately would approve. n65 The Companies could not rationally have expected the other parties, let alone us, to take on faith that we need not review their complicated tax and power purchase revisions. And their decision, for whatever reason, to refrain from filing their revisions until the end of the hearings (their negotiations obviously had taken place over many months, and the new documents prepared over the course of several weeks) left us no choice but to order supplemental testimony and hearings. Under the circumstances, we could readily have decided that we could not issue this Order by the Companies’ closing deadline -- they can, of course, extend the deadline themselves until at least December 17, 2009, n66 and our statutory deadline for reviewing the Application does not expire until about the same time. n67 We have decided, [*37] however, that it is important to maintain the schedule whenever we can without compromising the depth and quality of our review, and we have driven the other parties and ourselves as hard as possible to maintain that standard. n68

n65 PUC § 6-105(f)(6)(requiring the application to include detailed information regarding all documents relating to the transaction).

n66 See Phase I CEG Exhibit 5 (Master Put Option and Membership Interest Purchase Agreement § 8.1).

n67 See PUC § 6-105(g)(6). The Application was filed on June 19, 2009.

n68 It is worth noting here that for all of the Companies’ complaints about the delay they claim this case has caused, they could not have closed the Transaction before October 8, 2009 -- the day they received the necessary approvals from the United States Nuclear Regulatory Commission (“NRC”). See "Order[s] Approving Application Regarding Proposed Corporate Restructuring," issued by NRC on October 8, 2009. Even if we had decided in Phase I that EDF would not acquire the power to exercise substantial influence, CEG and EDF would still have had to wait for the NRC approval before closing. This means that the original September 17 closing date was not tenable, with or without these proceedings. The fact that the Companies now have received their NRC approvals has influenced our approach to these latest developments. Because this case now (but only now) represents the last regulatory hurdle before closing, we have pushed the other parties and ourselves harder to work through the late-breaking issues by the existing deadline.

[*38]

Stated generally, the new revisions to the Transaction are designed to achieve longer-term tax savings for the Companies and to reorient the post-closing power purchase and sale agreements among CENG, CEG and EDF. n69

n69 Oct. 14 Tr. at 2433-2461 (Panel Testimony of John Morris, Michael Wallace and John Collins).

First, they propose to achieve tax savings by reconfiguring the underlying purchase by EDF of CENG's nuclear assets as a purchase in part and a contribution in part. To accomplish this, CEG would form two new entities. The first,
Constellation Nuclear, LLC ("Constellation Nuclear"), would be owned wholly by CEG and formed for the purpose of holding 99% of the interests in CENG. n70 The second, CE Nuclear, LLC, would be a subsidiary of Constellation Nuclear and would be formed for the purpose of holding the remaining 1% interest in CENG. n71 Rather than having EDF purchase its interest in CENG in one step, the revised Transaction would have Constellation Nuclear sell a 49.99% interest in CENG to EDF in [**39**] three steps: a cash payment by EDF to Constellation Nuclear of approximately $3.8 billion, a $670 million capital contribution by EDF to CENG, and a distribution by CENG to Constellation Nuclear and CEG of $379 million and $291 million, respectively. The end result is the same -- EDF would own a 49.99% interest in what is now CENG in exchange for approximately $4.5 billion in payments by EDF, subject to "immaterial" adjustments n72 -- but the new structure apparently would create a more favorable future tax structure for both Companies. n73

n70 See Phase I CEG Exhibit 5 (Master Put Option and Membership Purchase Agreement), as amended by Phase II Joint Exhibit II-1A (Amendment 2 to Master Put Option and Membership Purchase Agreement at 1).

n71 See Phase I CEG Exhibit 5 (Master Put Option and Membership Purchase Agreement § 1.6), as amended by Phase II Joint Exhibit II-1A (Amendment 2 to Master Put Option and Membership Purchase Agreement).

n72 Oct. 14 Tr. at 2601 (Panel Testimony of John Morris, Michael Wallace and John Collins). These purchase price adjustments include downward adjustments for one-half of the amount of accrued and unpaid bonuses for CENG employees for the year ending December 31, 2009, one-half of the fee payable under certain arrangements with Constellation Energy Commodities Group, Inc. ("CECG") and one half of certain pension costs relating to CENG's and its subsidiaries' employees. See Phase I CEG Exhibit 5 (Master Put Option and Membership Purchase Agreement § 1.4), as amended by Phase II Joint Exhibit II-1A (Amendment 2 to Master Put Option and Membership Purchase Agreement).

n73 Oct. 14 Tr. at 2465-2469 (Panel Testimony of John Morris, Michael Wallace and John Collins).

Second, CEG and EDF revised the agreements defining CEG's, CECG's and EDF's rights after closing regarding the electricity generated by the nuclear plants and the timing and priority of CENG's cash distributions to CEG and EDF. n74 With regard to the output from the existing nuclear plants, the Companies have negotiated a complex series of power purchase agreements that would govern their future transactions. n75 A revised operating agreement also requires CENG to make cash distributions to its owners in a specific order of timing and priority. n76

n74 See Joint Exhibit II-1B (Second Amended and Restated Operating Agreement).

n75 See Joint Exhibit II-1D (Form of Power Purchase Agreements).

n76 See Joint Exhibit II-1B (Second Amended and Restated Operating Agreement § 6.1).

In addition to these broader revisions, [**41**] the Companies have revised other, less central elements of the deal:

. The put option was amended to restrict CEG from "putting" C.P. Crane to EDF until all put assets, other than Safe Harbor, Panther Creek/Colver, Sunnyside Cogeneration and ACE Cogeneration, have been exercised. n77

. CENG agreed to pay CECG up to $87.5 million in consideration for power scheduling and energy management services to be provided by CECG to CENG on behalf of the
Calvert Cliffs, Nine Mile Point and Ginna nuclear facilities (collectively, the "Nuclear Assets").

EDF is no longer obligated to make a payment to CEG relating to outstanding performance units that would have been payable by CEG as if a change in control had occurred.

CEG is obligated to cover certain shortfalls in the nuclear decommissioning trusts relating to the Nuclear Assets.

CENG will establish a separate pension fund for its and its subsidiaries' employees.

See Phase I CEG Exhibit 5 (Master Put Option and Membership Purchase Agreement § 2.2), as amended by Phase II Joint Exhibit II-1A (Amendment 2 to Master Put Option and Membership Purchase Agreement).

EDF is no longer obligated to make a payment to CEG relating to outstanding performance units that would have been payable by CEG as if a change in control had occurred. According to the testimony of Mayo Shattuck, in Phase I, EDF would have been obligated to pay up to $32 million under the original agreement. Transcript of Phase I Hearing, April 28, 2009, at 660-661 (Panel of Mayo Shattuck and Michael Wallace). By the time of the Phase I hearings, CEG had decided it would not pay amounts related to the performance units, id. at 460, but until we received the revised Transactions documents, we believed EDF still was required to make this payment.

See Phase I Order at 10. According to the testimony of Mayo Shattuck, in Phase I, EDF would have been obligated to pay up to $32 million under the original agreement. Transcript of Phase I Hearing, April 28, 2009, at 660-661 (Panel of Mayo Shattuck and Michael Wallace). By the time of the Phase I hearings, CEG had decided it would not pay amounts related to the performance units, id. at 460, but until we received the revised Transactions documents, we believed EDF still was required to make this payment.

According to Mr. Wallace, the NRC has not yet determined whether the trusts for the Calvert Cliffs plants, the Nine Mile Point plants or the Ginna plant have shortfalls that need correcting. Oct. 14 Tr. at 2617 (Panel Testimony of John Morris, Michael Wallace and John Collins).

In reviewing this Transaction against § 6-105(g)'s public interest standard, we have considered all of the terms of the Transaction included in the documents admitted in the record of this case as of the end of the hearing on October 14, 2009. Our decision below, which approves the Transaction with conditions, authorizes the Companies to close the Transaction only in the form described in the Transaction documents as filed with the Commission, and may be amended only to satisfy the conditions and requirements in this Order.

**III. ANALYSIS AND DECISION**

**A. The "Public Interest" Standard**

It was true in Phase I, and remains true, that this is the first case in which we are called upon to apply § 6-105(g) to a proposed "acquisition[] by [a person] not engaged in the public utility business in the State of the power to exercise
any substantial influence over the policies and actions [*44] of a public service company that provides electricity." n82

Having decided in Phase I that EDF would, in fact, "acquire the power to exercise... substantial influence over the
policies and actions of BGE, n83 § 6-105(g) requires us to "examine and investigate" the Application n84 and
"undertake any proceedings necessary or convenient to review the application in accordance with Title 3 of this article
and issue an order concerning the acquisition." n85 At the close of the proceedings, during which the applicant has the
burden of proof, we have three options, two of which are stark and binary. If we find that the acquisition is "consistent
with the public interest, convenience and necessity, including benefits and no harm to consumers, the Commission shall
issue an order granting the application," n86 and if we reach the opposite conclusion, we "shall issue an order denying
the application." n87 But there is a middle ground too. Rather than denying outright an application that falls short on its
face, we also "may condition an order authorizing the acquisition on the applicant's satisfactory performance or
adherence to certain requirements." n88

n82 PUC § 6-105(b)(2).
[*45]
n83 PUC § 6-105 (e)(1).
n84 PUC § 6-105 (g)(1)(i). EDF is the official applicant, since it is the party that would acquire the power to
exercise substantial influence in the Transaction. Whether we say that CEG or BGE must fulfill a condition or
that EDF cannot close the Transaction unless it can ensure that a condition is met, the result is exactly the same.
Our directions should be construed as conditions of closing the Transaction in which EDF acquires the power to
exercise substantial influence.
n85 PUC § 6-105(g)(2)(ii).
n86 PUC § 6-105 (g)(3)(i) (emphasis added).
n87 PUC § 6-105 (g)(4) (emphasis added).
n88 PUC § 6-105 (g)(3)(ii).

Section 6-105(g)(2) lists the factors we must consider in evaluating the "public interest" question, although the
"catch-all" [*46] factor at the end means that the list is not exhaustive:

(i) the potential impact of the acquisition on rates and charges paid by customers and on the services and
conditions of operation of the public service company;

(ii) the potential impact of the acquisition on continuing investment needs for the maintenance of utility
services, plant, and related infrastructure;

(iii) the proposed capital structure that will result from the acquisition, including allocation of earnings
from the public service company;

(iv) the potential effects on employment by the public service company;

(v) the projected allocation of any savings that are expected to the public service company between
stockholders and rate payers;

(vi) issues of reliability, quality of service, and quality of customer service;

(vii) the potential impact of the acquisition on community investment;
(viii) affiliate and cross-subsidization issues;

(ix) the use or pledge of utility assets for the benefit of an affiliate;

(x) jurisdictional and choice-of-law issues;

(xi) whether it is necessary to revise the Commission’s ring-fencing and code of conduct regulations in light of the acquisition; and

(xii) [*47] any other issues the Commission considers relevant to the assessment of acquisition in relation to the public interest, convenience, and necessity. n89

n89 PUC § 6-105 (g)(2) (emphasis added).

We read § 6-105(g) as giving us broad discretion within a narrow legal space. It is not our place to decide whether the Transaction is a good or bad idea, nor to weigh it against alternative deals or the status quo. We are charged instead with the task of ascertaining the “public interest, convenience and necessity” vis-a-vis the proposed Transaction and then, within that broader public interest notion, whether the Transaction will offer “benefits and no harm to consumers.” n90 As we explain below, “public interest,” “benefits...to consumers” and “no harm...to consumers” are separate concepts that require separate findings, n91 and thus we cannot, as the Companies might prefer, find simply that the people of the State of Maryland are better off generally with this [*48] deal than without it. But after working carefully through each of the issues, we find that a reasonable set of conditions will satisfy all of the statutory elements. We walk through those issues, and our conclusions regarding the necessary conditions, in Section III.C below.

n90 PUC § 6-105 (g)(3)(i).

n91 See pp. 32-34 below.

B. This Case is Not a Referendum on Nuclear Power, Re-regulation, or Good Corporate Citizenship

Before digging into the public interest analysis itself, we feel compelled to say something about issues that are not part of this case. As always, we are reluctant to address matters and decide questions not squarely presented. In this case, the public and political debate around our proceeding unfortunately has assumed a life of its own, and at times has left us scratching our heads wondering if the case being discussed is the case we are deciding.

First, we are mystified by the way in which this case has been cast as a referendum [*49] on a new nuclear power plant at Calvert Cliffs. This is absurd on its face, of course, because this Transaction and the documents executed to effectuate the Transaction relate only to CEG’s existing nuclear fleet, not to the proposed Calvert Cliffs 3. Our Phase I Order correctly took pains to exclude any consideration of the rights and powers that EDF has vis-a-vis UniStar Nuclear Energy, LLC (“UniStar”), the joint venture CEG and EDF formed to develop Calvert Cliffs 3. n92 Calvert Cliffs 3 will happen only if UniStar decides to pursue it, and that nothing about our approval of this Transaction requires it to do so.
Messrs. Morris n93 and Wallace n94 both expressed optimism about the prospects for the plant, but acknowledged that it depends on "thousands of factors," n95 including pending decisions by the United States Department of Energy, the Nuclear Regulatory Commission ("NRC"), the financial community and, of course, UniStar. n96 And Mr. Wallace acknowledged that an ultimate decision [n90] by UniStar to build Calvert Cliffs 3 is years away, n97 even though, as the Companies well know, Calvert Cliffs 3 already received from this Commission its Certificate of Public Convenience and Necessity ("CPCN"), n98 and thus cleared all of its State regulatory hurdles before this Phase began.

So why the confusion? Because as soon as this [n91] case entered Phase II, the Companies undertook an extensive and expensive public relations campaign designed to elicit support for the Transaction on the ground that Maryland will benefit from the development of Calvert Cliffs 3. n99 The full-page newspaper ads may not have promised explicitly that UniStar will build the plant if we approve this Transaction. But the orchestrated parade of Company employees, public officials and union leaders who appeared at our evening hearings connected those dots, and quite clearly believed that our approval of this Transaction would deliver the jobs and economic development benefits they want.

This campaign did not distract us from the issues in this case, but has challenged others' ability to remain focused on what this case actually entails. CEG and EDF have, to be sure, represented that a decision not to approve the Transaction or a decision to approve the Transaction with "unreasonable" conditions will [n92] cause them to terminate consideration of Calvert Cliffs 3. n100 But even if that is true, the Companies make no promises or guarantees that a decision approving the Transaction, even consistent with their proffered conditions, ensures the plant will be built. And for that reason, as we discuss below, the potentially substantial economic impact of Calvert Cliffs 3 on our State cannot qualify as a "benefit[...to consumers"] for purposes of our analysis here.
We can, however, offer one bit of comfort to concerned citizens. Many opponents of this Transaction expressed the fear, borne of the history of nuclear power in the 1960s and 1970s, that a decision by UniStar to build Calvert Cliffs 3 will expose BGE's ratepayers to the cost of building the plant and the risk of potential cost overruns. Under the current regulatory regime, however, UniStar will bear all of the financial risks of constructing, operating and decommissioning Calvert Cliffs 3, and the ratepayers will bear none. This does not, of course, address legitimate concerns about nuclear safety or broader policy questions about the wisdom of nuclear power -- those lie largely with the United States Nuclear Regulatory Commission (which has a long safety and engineering review to complete before it makes any decision to issue licenses to construct the plant), and other governmental entities.

Second, the record in this case affords us no basis on which to "re-regulate" all or any part of the Maryland electricity markets. As we have explained in our reports to the General Assembly, n101 we use the term "re-regulation" with some caution, since it can mean different things to different people. In this case, some have urged us to include in this Order conditions requiring CEG either to transfer electric plant ownership to BGE, n102 to require CEG to enter into long-term cost-of-service electricity contracts, n103 or to require CEG to provide the output from its generation stations to BGE customers on a cost-of-service basis. n104 But only one party who submitted testimony n105 even advocated a condition of that nature. n106 And none made the case that the law even allows conditions like that, let alone that the public interest compels them.

Third, it is worth noting that the post-1999 regulatory regime in Maryland leaves the corporate behavior and decisions of CEG itself unregulated. We can step in when, as here, the law specifically allows it, or if CEG's decisions implicate the financial health and well-being of BGE -- such as, for example, when CEG allocates costs to BGE or makes decisions regarding BGE's access to capital. But as a general matter, the law leaves CEG free to act as its management and Board of Directors think best, and leaves its investors and shareholders, rather than regulators, to serve as checks and balances.

We know that members of the public are frustrated by the magnitude of CEG's (and other corporations') executive compensation, particularly since the Chief Executive Officer and Board of Directors to whom we must entrust BGE after this Transaction are largely the same CEO and Board who guided CEG and BGE to the brink of bankruptcy just over a year ago. We understand these concerns. But even if we might, as individuals, question the wisdom of paying...

n101 "Interim Report of the Public Service Commission of Maryland to the Maryland General Assembly" (December 3, 2007).

n102 Correspondence from Senators Pipkin and Rosapepe to Chairman Nazarian (September 14, 2009).

n103 Hooke Direct Testimony at 16-17.

n104 We understand, based on letters submitted as exhibits during the hearing, that settlement discussions between the State of Maryland and CEG included requests by the State that CEG agree to provide SOS electricity to BGE on a regulated basis. See Staff Exhibit II-6. Those discussions obviously did not result in an agreement, however, and the State's litigation position did not include any recommendations of that sort.

n105 Mr. Hooke, on behalf of the Maryland Tax Education Foundation, recommended that we order CEG to provide Standard Offer Service electricity to BGE on a cost-of-service basis. Hooke Direct Testimony at 16-17. His recommendation depended, however, on the untenable assumptions that CEG sells its output to BGE to serve the SOS load and that EDF would be willing to proceed with the Transaction even if its revenues from the existing nuclear plants were reduced under cost-of-service contracts. Transcript of Phase II Hearing, Sept. 18, 2009 ("Sept. 18 Tr.") at 1860-1862. The record points to exactly the opposite conclusion. What EDF is getting from this deal is a partnership with CEG to operate and develop nuclear power plants and we think it would be bad public policy, even assuming we even had the authority to do so, to try to rewrite existing power supply contracts.

[*55]
anyone millions of dollars per year given CEG's recent history, it is our role as Commissioners to focus on BGE and its ratepayers. And CEG's executive compensation enters our regulatory sphere only when BGE seeks to pass on some portion of those compensation packages in its distribution rates, which have not changed since BGE's last electric rate case in 1993 and its last gas rate case in 2005.

This history does come into play, however, as we look ahead to the future of BGE after this Transaction would close. The parent's business decisions and priorities -- such as its earlier (and nearly fatal) focus on risky, collateral-intensive trading operations -- have, at times, placed BGE in danger of financial harm. So even though CEG claims now to have changed its business model, we have to consider and protect BGE against the possibility that CEG's approach could just as easily revert to prior form. We also need to protect BGE against the impact of the Transaction, which refocuses CEG to capital intensive nuclear expansion.

n106 See Sept. 15 Tr. at 872-878 (Panel of Michael Wallace and John Collins).

C. Properly Conditioned, the Transaction is Consistent With the Public Interest, Convenience and Necessity, With Benefits and No Harm to Ratepayers

1. The Standard Requires Three Separate Findings

Against this contextual backdrop, we return to §§ 6-105(g)(3) and (4). Both of our threshold options -- to approve or deny the Application -- require us to make a finding as to whether the Transaction "is consistent with the public interest, convenience and necessity, with benefits and no harm to consumers." n107 Before we can analyze the record against this standard, however, we must decide two questions.

n107 PUC §§ 6-105(g)(3) and (4).

First, the language of the statute distinguishes "the public interest" from "benefits and no harm to consumers." The "public interest, convenience and necessity" is a broader concept of greater good, and the Transaction need only be "consistent" with that notion to satisfy that element. We read this language to say that there is no one absolute form that this or any other transaction must take to pass public interest muster, and that the General Assembly is not vesting us with carte blanche "blue pencil" authority to renegotiate deals to fit a specific, defined vision. n108 Our authority to condition an approval order is important and non-trivial, but requires us to work within the framework of the Transaction before us. We see this in the structure of the statute: if a proposed transaction cannot be made consistent with the public interest (or the benefits and harms addressed) through conditions, the statute instructs that we "shall issue an order denying the application." n109


n109 PUC § 6-105(g)(4).

At the same time, the specific reference to "benefits and no harm to consumers" requires us to find
separately, and additionally, that the Transaction: (a) will yield benefits to consumers; and (b) will not cause harm to consumers. Because the General Assembly required that the public interest finding "include" these elements, the Transaction cannot satisfy the overall statutory requirement without a finding that it satisfies them individually. We are free to consider other aspects of the Transaction that might not qualify as "benefits" or measures to ensure "no harm" in the broader "public interest" analysis. But unless we can find that the Transaction yields "benefits" and will cause "no harm," we cannot approve it.

Second, in order to have any meaning, the term "consumers" can only include the consumers of the public service company as to whom "substantial influence" is being acquired -- in this case, the consumers, or ratepayers, of BGE. This flows from the same reasoning, and the same portion of the sentence, as the "benefits and no harm" clause. By separating "consumers" benefits and harms from the broader "public interest, convenience and necessity," the statute requires the relevant consumers to receive something different than benefits to society [*60] at large. Put another way, reading "consumers" to include the citizens of the State of Maryland, as the Companies say we should, n110 reads any substantive difference between the "public interest" and "benefits to consumers" out of the statute. And since we, like a court, must read statutes in a way that gives meaning to each word or phrase, n111 the Transaction's benefits and protections must accrue directly to BGE's ratepayers.

n110 Wallace and Collins Rebuttal Testimony at 4-5; Morris Rebuttal Testimony at 6-10.

n111 Board of Education v. Lendo, 295 Md. 55, 63 (1982).

Accordingly, § 6-105(g) requires us to analyze three distinct questions:

a. Is the Transaction consistent with the public interest, convenience and necessity?

b. Will the Transaction yield benefits to BGE ratepayers?

c. Is the Transaction structured not to harm BGE ratepayers?

For the reasons that follow, we find that we can answer all three questions in the affirmative, within the structure of the [*61] Transaction as proposed, so long as the Companies satisfy a reasonable set of conditions.

2. The Transaction Is Consistent Generally with the Public Interest, Convenience and Necessity

The Transaction is consistent with the public interest, convenience and necessity on a number of levels. First, CEG is a Maryland-based company, the parent of our largest regulated utility, and one of the few Fortune 500 companies based in Maryland. If the Transaction closes, CEG will emerge from the Transaction with significantly less debt, a stronger balance sheet, and its existing structure intact. Although we do not subscribe blindly to the 1950s' notion that "what's good for [Constellation Energy] is good for [Maryland]," n112 we cannot forget that CEG careened toward bankruptcy only thirteen months ago. As we explain below, more of the new-found financial stability needs to be shared with BGE than the Companies have offered on their own. But in the right context, an outside investment in CEG's assets that stabilizes CEG's finances is consistent with the general public interest in having a financially stable utility company, BGE, that can provide safe and reliable electric service to half [*62] of our State at just and reasonable rates. We also recognize that a financially sound corporate citizen, which funds charitable organizations in Maryland, is a benefit to our State.

"According to the press, [former General Motors executive and Secretary of Defense candidate Charles] Wilson told the Senators: 'What's good for General Motors is good for the country.' What he actually said: 'For years I thought that what was good for our country was good for General Motors, and vice versa.'"

Second, a decision by UniStar to develop Calvert Cliffs 3 could, at some point, have a substantial and positive economic impact on the State and people of Maryland. The Companies have devoted a large proportion of their live and written testimony to quantifying this impact, and a similar effort to sell the project to the public at large, all in the apparent hope that we would[*63] see Calvert Cliffs 3 as an offer we couldn't refuse. But the Companies are not offering anything in that regard beyond a possibility if we approve this Transaction and a threat -- to pull the plug entirely -- if we do not. n113

n113 Sept. 14 Tr. at 191 (John Morris) ("I would say [a] decision [not to proceed with Calvert Cliffs 3 would be] made because EDF would feel that it is not welcome as an investor in nuclear in Maryland.").

For the purpose of the "benefits...to consumers" requirement, we ascribe no value to the possibility of Calvert Cliffs 3, enhanced or not, because any benefits that would accrue from Calvert Cliffs 3 are highly contingent. Even if approving this Transaction makes Calvert Cliffs 3 more likely, a meaningful commitment to construct it is at least three years away n114 and depends on UniStar's ability to surmount "thousands of factors," including but not limited to a lengthy NRC licensing process, uncertain loan guarantees from the Department of Energy, equally (or more) uncertain financing, [*64] and the Companies' ongoing but uncertain assessment of the economic viability of the plant. That said, Maryland's electricity markets are restructured, and the current law and policy of our State leave decisions about whether and when to construct power plants primarily to the marketplace. n115 As such, the Transaction is consistent with the public interest, convenience and necessity to the extent it is consistent with the restructured market environment the General Assembly sought in 1999 to create in Maryland.

n114 Sept. 15 Tr. at 827 (Panel of Michael Wallace and John Collins).

n115 See PUC § 7-504; § 7-510.

Moreover, after a separate and thorough process, we already have reviewed and granted UniStar's application for a CPCN for Calvert Cliffs 3, n116 which in turn required us to find that the proposed plant is consistent with the public interest, convenience and necessity. n117 For that reason, we do not analyze here whether Calvert Cliffs 3 should be[*65] built. The critical nuclear safety issues are not ours to decide in the first place -- they lie with the NRC, and the project has satisfied all Maryland state regulatory requirements. At this point, Maryland law leaves the decision to build the plant or not to its developer, in this case, UniStar. With or without this Transaction, UniStar could build Calvert Cliffs 3 with the right federal permits and financing. To the extent approving this Transaction enhances the likelihood the plant is built, our decision adds no new risks to our State that have not already been considered, or will be considered, in the appropriate regulatory forum.

n116 In the Matter of the Application of Unistar Nuclear Energy, LLC, and Unistar Nuclear Operating Services, LLC for a Certificate of Public Convenience and Necessity to Construct a Nuclear Power Plant at Calvert Cliffs in Calvert County, Maryland, Case No. 9127, Proposed Order of Hearing Examiner (April 28, 2009) and Order
Third, upon closing, the Transaction will generate a one-time tax payment to the Maryland General Fund of approximately $129 million. Because this payment goes to the Maryland Treasury rather than BGE's ratepayers, it cannot qualify as a "benefit...to consumers." And as such, we need not resolve the dispute between the Companies and OPC about the net value to the State of the tax payments the Companies will make at and after closing. Regardless, in this time of State budget crisis, a lump-sum payment of $129 million to the Maryland General Fund is consistent with the public interest, convenience and necessity, and any future tax savings the Companies might realize would not be inconsistent so long as the Companies follow the tax laws.

Fourth, the Transaction may yield other positive outcomes in Maryland. EDF has promised to relocate its U.S. headquarters to Maryland, a move that could create opportunities for further economic development above and beyond the existing plants and Calvert Cliffs 3. And although we condition approval of the Transaction on a rate rebate designed to be revenue neutral, we hope that CEG or EDF will fund the Constellation Energy Group Foundation and construct a visitor center at Calvert Cliffs. These proposals would further broaden public interests in philanthropy, education and economic development. But the positive impacts from enhanced philanthropy and the visitor center are too contingent and indirect to qualify as "benefits...to consumers," but they bolster the Transaction's general consistency with the public interest, convenience and necessity.

Fifth, CEG has offered, and we accept their offer, to provide, at no cost to BGE, a generation site if and when BGE proposes, or the Commission orders BGE, to build new generation in Maryland. Like the construction of Calvert Cliffs 3, this benefit is too uncertain to qualify as a direct benefit to ratepayers as required by statute. But to the extent this commitment -- which we direct CEG to honor as a condition of closing -- facilitates future construction of new electric generation in Maryland, it supports our finding that the Transaction, properly conditioned, is consistent with the public interest.

Chairman Nazarian: If the transaction is approved, including the condition that Constellation will make available to BGE a site on which BGE can build power, and either we order or BGE builds a power plant, are we going to hear that that alters the Maryland electricity market and so Calvert Cliffs 3 won't get built?

Mr. Wallace: No.
3. The Companies Must Provide Benefits Directly to BGE Ratepayers in the Form of Rate Relief.

Having found that the "benefits" touted in [*69] support of the Transaction cannot qualify as "benefits...to consumers" under § 6-105(b)(3)(i), we reach the question of "what does?". The answer is not a reflexive recitation of the words "rate relief," although rate relief undeniably "benefit[s]...consumers." Instead, the statute allows us to view the form of the "benefit" flexibly so long as the benefits inure directly to consumers, i.e., BGE's ratepayers, and are neither contingent nor intangible. This strikes us as a reasonable statutory bargain. We know that in any transaction subject to § 6-105, the buyer acquires the power to exercise substantial influence over the utility, and the utility itself (or in this case, its parent) gets paid. By requiring "benefits...to consumers" separately from "the public interest, convenience and necessity," n123 the General Assembly meant for ratepayers to receive something as well, something more than a possibility.

n123 PUC § 6-105(g)(4).

These "benefits" need not always [*70] take the form of money or discounted rates. In the context of this Transaction, however, none of the benefits the Companies identify offers a certain, direct benefit to consumers. All of the Companies' proposals either are too uncertain (Calvert Cliffs 3, the offer to provide a potential generation site, the relocation of EDF's headquarters and rate case limits) or indirect (tax payments, charitable contributions and a visitor center) or both. And other Company proffered conditions qualify as protections against harm (ring-fencing reforms), a finding we must (and do) make separately.

We could, we suppose, look at the fact that CEG will emerge from this Transaction with net proceeds on the order of one billion dollars after retiring debt and divert a large portion of those proceeds to rate relief. We will resist the temptation. CEG is entitled to the fair proceeds of a properly conditioned Transaction, and § 6-105 does not give us unbridled authority to restructure the deal or fundamentally alter its outcome. So although we find that the only way to achieve "benefits...to consumers" in the context of this Transaction is to order a rate rebate, we will do so in a principled manner that [*71] still allows CEG to accomplish its post-closing goals.

This can be accomplished by a reasonable rate rebate. We order CEG to fund, as a condition of approval, a one-time per customer distribution rate credit for BGE residential customers, before the end of March 2010, in the amount of $ 110.5 million. We obtain this figure by combining three payments EDF has agreed, in the course of this deal, to make above and beyond the $ 4.5 billion purchase price -- $ 32 million that EDF had agreed to pay to fund CEG's Long-Term Incentive Plan, n124 $ 20 million that EDF agreed to pay for the construction of the visitor's center at Calvert Cliffs, $ 36 million that EDF had agreed to contribute to the Constellation Energy Group Foundation -- with the $ 22.5 million CEG has offered to provide in rate relief in lieu of a proposed 2.5% cap on BGE's next rate case. We are not requiring that the Companies use the pools of money identified above to fund the rate relief -- we hope they will follow through on those commitments regardless. We base the amount of the rebate on payments falling outside the base purchase price in order to eliminate the financial impact of this condition to CEG or, if not, to [*72] keep it within the range of "immaterial" n125 pre- or post-closing adjustments.

n124 We understand that the latest round of revisions to the Transaction documents eliminated EDF's obligation to fund CEG's Long-Term Incentive Plan. In response to press coverage of its bonus plans, CEG announced before Phase I that it did not intend to pay bonuses under the Plan, and Mr. Berardesco testified during the Phase I hearing that CEG would use EDF's payment for "general funds of the company." Transcript of Phase I
Hearing, April 28, 2009, at 459 (Charles Berardesco); see also id. at 660-661 (Panel of Mayo Shattuck and Michael Wallace) (the $32 million payment will be available for "general corporate purposes"). We have not attempted to flyspeck the original and current Transaction documents to determine whether the overall purchase price has been reduced by this $32 million or netted out in some other fashion.

We will not pretend that this rebate, which will amount to approximately $100 [\*73] per residential customer, will make a significant difference on anyone’s bill, although every little bit helps. We find, however, that this rebate represents a fair, concrete and certain benefit to consumers in the context of this Transaction.

4. CEG Must Take Steps to Ensure that the Transaction Causes No Harm to Ratepayers

The final step in the § 6-105 analysis requires us to find that the Transaction will cause "no harm to consumers." For the same reasons we focused our "benefits...to consumers" analysis on BGE ratepayers, we focus here on BGE ratepayers as well, and read the "no harm" standard as requiring us to ensure that the Transaction does not create new harms or risks or add to those BGE's ratepayers already face.

a. Potential Harms

As in Phase I, where we found that EDF takes CEG as it finds CEG for purposes of the "substantial influence" analysis, n126 we analyze the potential harms to BGE's ratepayers in context. We are here today, reviewing this Transaction, because CEG's business strategy and decisions in its unregulated businesses led CEG to the brink of bankruptcy in mid-September 2008. Whatever the causes and wherever the blame properly lies, we suspect that [\*74] had CEG filed for protection under the bankruptcy laws at that point, as it very nearly did, BGE would not have been spared. We know that although senior CEG executives have testified under oath that the Company has changed its business strategy to avoid the risks that nearly drove it to bankruptcy, they admit that nothing prevents CEG from reverting to its earlier, riskier business model if broader conditions changed. n127 And we know as well that largely the same Board of Directors, and the same Chief Executive Officer, who led CEG in 2008 lead CEG to this day.

n126 Phase I Order at 22.

n127 Sept. 15 Tr. at 872-878 (Panel of Michael Wallace and John Collins).

Against this backdrop, we have identified two sets of potential harms that must be addressed structurally before we can approve this Transaction.

First, as we found in Phase I, the greatest potential impact on BGE derives from the new joint venture's (and thus EDF's) ability to influence the flow of capital in and out of CENG, and thus the capital [\*75] available to CEG and ultimately to BGE. n128 Even before this Transaction, capital within CEG was "scarce" by CEG's own reckoning. n129 This matters for ratepayers because inadequate capital affects BGE's ability to fund the amounts necessary to maintain safe and reliable distribution systems and reduces BGE's equity ratio, which in turn can damage BGE's credit rating. n130 Much has been made in this case of the role of credit rating agencies and their perceptions of CEG, BGE, this Transaction and the regulatory climate in Maryland. BGE's credit rating is important to ratepayers. The lower BGE's credit rating, the harder it is for BGE to obtain capital to fund its operations, which increases BGE's borrowing costs n131 and creates pressure to collect more revenue through rates. To the extent, then, that the Transaction creates greater competition for capital within the CEG corporate family -- or, put another way, if CEG is not investing enough in BGE, or if CEG treats BGE as a source of capital for its other operations -- ratepayers face the possibility of diminished service quality and higher rates. Since BGE's credit rating is tied closely to CEG's -- BGE's rating was downgraded
[*76] in September 2008, when CEG was downgraded n132 -- CEG's corporate decisions and behavior place BGE's rating, and thus BGE's ratepayers, at risk. CEG's increasing commitment to nuclear power, a business rating agencies find risky at best, n133 only magnifies the risk to BGE.

n128 Phase I Order at 24-34.
n129 Transcript of Phase I Hearing, April 27, 2009, at 231 (Panel of Mayo Shattuck and Michael Wallace).
n130 Phase I Order at 28.
n131 Staff Witness Frayer testified that there is a 19.35 basis point spread in the cost of money (i.e., the difference between interests rates associated with a debt offering), from a one-notch downgrade in credit rating from BBB to BBB- for a company like BGE. Frayer Testimony at 18-19.

n132 See CEG Preliminary Schedule 14A dated Nov. 24, 2008 at 9. See also Phase I CEG Ex. 29 (Response to MEA/State Data Request 2).

The structure of the Transaction that [*77] existed when we issued our Phase I Order granted the EDF-nominated directors on the CENG board the right to veto distributions made from CENG to CEG and EDF, its members. At that time, we voiced our concern that the veto power gave EDF the right to prohibit the flow of dollars that typically would have been distributed from CENG to CEG. n134 Since the Phase I Order, however, the Companies have amended the Transaction to require CENG to make capital distributions to EDF before making any to CEG in certain circumstances, which does not require approval by the CENG Board of Directors. In fact, the only time those mandatory distributions cannot be made is when there is insufficient cash on hand at CENG or if any agreements to which CENG is a party restrict payment of cash from CENG. So whereas our concern centered originally around the ability of the EDF Board members to elect to limit distributions to CEG, the revised terms limit distributions to CEG even more. This limits further still the capital available to CEG and its subsidiaries, including BGE.

n134 Phase I Order at 19-31.

[*78]

This capital scarcity can be compounded further, if (or when) BGE pays dividends to CEG. Although BGE has committed not to pay dividends in calendar 2009, n135 it has paid well over a billion dollars in dividends to CEG since 1999, including $ 171 million in dividends in the five months immediately preceding CEG's liquidity meltdown, leaving BGE's equity ratio hovering near 40%. n136 The BGE Board of Directors decides whether to pay dividends and to what extent. n137 But the BGE Board is dominated by CEG executives and directors who make dividend decisions based on CEG's financial needs and plans, n138 and history demonstrates that CEG will look to BGE when it needs cash. The fact that BGE is a regulated utility and may be able to pass a higher cost of borrowing onto ratepayers may even create an incentive for CEG to tap BGE to help its unregulated subsidiaries, who can not pass on the costs associated with borrowing. Without some limit on BGE's ability to pay dividends to CEG, CEG can err on the side of extracting cash from BGE, knowing that any increased costs could be borne by ratepayers, which, given the makeup of the BGE Board, leaves BGE at a disadvantage.

n135 Transcript of Phase I Hearing, May 4, 2009, at 1475-1476 (Kenneth W. DeFontes, Jr.).

[*79]
Second, BGE remains vulnerable to a CEG bankruptcy. This was true in 2008, to be sure, although the proceeds from the Transaction should strengthen CEG’s balance sheet, at least in the immediate term. But in selling not-quite-half of its existing nuclear fleet, CEG will have sold half of the income from those plants, fully 15% of the Company’s overall earnings. Although BGE’s ratepayers will not bear directly the cost (and potential cost overruns) of developing new nuclear plants, such as Calvert Cliffs 3, the intensity of the nuclear operations’ capital needs or a catastrophic failure of a nuclear project (operational or not) place the entire CEG corporate family at risk -- even more so as CEG’s commitment to nuclear energy grows. And the same liquidity and other risks that nearly forced CEG into bankruptcy could return if CEG abandons its de-risking efforts at some point in the future. Accordingly, we must, as a condition of approval, ensure that BGE is protected against its parent’s high-risk business strategies and pressures brought to bear by the closing of this Transaction.

b. Conditions

Without appropriate conditions, the Transaction increases BGE’s and its ratepayers’ exposure to these two categories of harms and, therefore, we could not approve it. We cannot approve it, then, without conditions that insulate (as much as possible) BGE from the damage CEG can do to BGE’s credit rating and against the possibility of a CEG bankruptcy. And just as CEG will emerge from this Transaction in much stronger financial condition -- after closing, CEG will use the proceeds of the Transaction to retire debt, increase its liquidity (i.e., the money available to invest in its operations), and improve its credit ratings so that it can finance its operations more easily and on more favorable terms -- so too should BGE. As CEG invests in itself and its nuclear future, it should invest capital in BGE as well, both immediately (from the proceeds of the Transaction itself) and in the future (by taking dividends from BGE only when BGE’s equity ratio remains sound). And when we all look back at this Transaction in a few years, BGE should have the same prospects for an improved credit rating and capital structure as CEG holds for itself, whether or not CEG sticks to its current, lower-risk business model or its bet on nuclear power pans out.

CEG proposed a series of conditions designed to create distance between CEG and BGE for purposes of bankruptcy protection and credit rating separation. These proposals are sound structurally and did not meet with fundamental objection from the other parties. CEG’s proposal focused more on formal ring-fencing than on the substantive financial health of BGE, however, and needs to be augmented in order to accomplish both goals. Accordingly, we hold that the Companies must satisfy the following, as conditions of approval, for the Transaction to satisfy § 6-105(g)(3)(i)’s “no harm to consumers” requirement:

**Condition 1:** CEG shall make a $250 million cash capital contribution to BGE by no later than June 30, 2010. CEG and BGE also shall report BGE’s debt/equity ratio to the Commission on a quarterly basis, on the 15th of the month following each calendar quarter.

A capital infusion from CEG to BGE represents a first, and critical step, in repairing BGE’s credit rating and ensuring that the Transaction strengthens BGE’s finances as well as CEG’s. CEG would appear to agree, based on the offer in the Rebuttal Testimony of Messrs. Wallace and Collins to pay “up to $250 million” to achieve an equity ratio, to be set by us, between 40-44%. But the offer itself is a totally empty one. In response to our questions at the close of
the hearing, CEG and BGE admitted that BGE's current equity ratio already falls within the Companies' target range (it is now 42.9%) and that no cash infusion would be necessary to achieve a 44% equity ratio by June 2010. n140 Although we appreciate their candor, the Companies' data response confirms our instinct that tying the cash infusion to their proposed equity ratio would render the "up to $ 250 million" pledge meaningless.

n140 Letter from Deborah Jennings, on behalf of CEG and BGE, to the Commission, dated October 23, 2009, Docket Entry No. 208.

[*83] As a general matter, the equity level the Companies propose for BGE is on the low end of acceptable, n141 even if it is true that a 40% ratio will get BGE an investment-grade credit rating. n142 But we need not, and do not, decide here what BGE's equity ratio ought to be -- that is a decision for another time, beginning with BGE's next rate case. In our view, the fact or amount of the cash infusion should not be determined by an equity ratio target -- CEG should invest cash in BGE to strengthen BGE's balance sheet, just as CEG is doing the same with its own. If the Companies are right that a $ 250 million cash infusion results in a 48% equity ratio, BGE will be all the stronger for it. We will not require here that BGE maintain that or any particular ratio going forward, but will monitor BGE's ratio through the quarterly reports and address the ratio itself, if appropriate, at another time.

n141 SNL Energy, "Regulatory Focus: Major Rate Case Decisions"; see also In the Matter of the Application of Delmarva Power and Light Company For An Increase in its Retail Rates for the Distribution of Electric Energy, Case No. 9192, Testimony of Dr. Roger Morin, Docket Entry No. 1, at 71.


**Condition 2:** Until further order of the Commission, BGE shall not pay dividends to CEG if, after the dividend payment, BGE's equity level would fall below 48%, as equity levels are calculated under this Commission's ratemaking precedents. BGE also shall not make any distribution to CEG if BGE's senior unsecured credit rating, or its equivalent, is rated by two of the three major credit rating agencies below the generally accepted definition of investment grade. In the event that the BGE Board resolves to pay dividends to CEG, BGE shall file with the Commission, within 5 business days after payment of the dividend, the calculations that it used to determine its equity level at the time the Board considered payment of the dividends and the calculations to demonstrate that the equity ratio after the dividend payment will not fall below 48%.

Given the increase in the competition for scarce capital within CEG, along with the history of BGE's non-independent Board declaring dividends, we find that BGE needs some measure of protection [*85] against the outward flow of cash at times when dividends would leave BGE weakened. The Companies agreed that BGE should not be paying dividends when its rating goes below investment grade, n143 so there is no quarrel there. But although we decline to establish a required equity ratio for all purposes, we find as well that BGE should not be paying dividends to CEG if the payment would lower BGE's equity ratio below 48% -- a figure supported by Professor Schwartz n144 and comparable with the ratios maintained by other Maryland utilities. n145 Just as a cash infusion provides immediate balance sheet strength, this dividend parameter protects BGE against cash outflows that would weaken it or deprive it of capital necessary to carry out its mission of providing safe and reliable electric and gas distribution service. This
limitation also helps to ameliorate our concern that the CEG insiders who dominate BGE's Board can vote to declare dividends when an independent Board, unfettered by CEG's interests, otherwise would not. This way, BGE can pay dividends when its books meet an objective standard of financial health, and cannot pay them otherwise -- a better and safer arrangement for the [*86] ratepayers, and one we can verify through reporting.

n143 Wallace and Collins Rebuttal Testimony at 34-35.

n144 Schwartz Direct Testimony at 30-33.

n145 See, e.g., In the Matter of the Application of Delmarva Power and Light Company for an Increase in its Retail Rates for the Distribution of Electric Energy, Case No. 9192, Order No. 81518 at 45 (finding Delmarva's equity level to be 48.63%).

Condition 3: BGE may file an electric distribution rate case at any time beginning in January 2010. BGE may not file a subsequent electric distribution rate case until January 2011. The timing of any gas distribution rate filing will also occur no earlier than the electric cases. CEG's allocation of costs under the four-factor formula shall be limited to 31% until the Commission reviews cost allocation in the context of BGE's next rate case. n146

n146 See Post-Hearing Brief of Constellation Energy Group, Inc. and Baltimore Gas and Electric Co. at Appendix A.

[*87]

Again, BGE's next distribution rate case already is capped at a 5% increase under the 2008 Settlement, and CEG's proposal to limit the potential increase further, to 2.5% (with caveats), may offer no new value to ratepayers since whether BGE is actually entitled to a rate increase is unknown. We instead choose to accept the Companies' offer to pay $22.5 million in immediate rate relief. BGE may file an electric distribution rate case at any time beginning in January 2010, and we accept CEG's offers not to file a subsequent rate case until at least January 2011 and its temporary limit on the costs CEG can allocate to BGE. n147 Finally, the timing of any gas distribution rate filing also will occur no earlier than the electric cases.

n147 Id.

Condition 4: Immediately upon the close of the Transaction, n148 CEG and BGE shall begin to implement the ring-fencing measures set forth in the Rebuttal Testimony of Charles Atkins to ensure the bankruptcy protection and credit rating separation of BGE from CEG, specifically: [*88] n149

a. CEG shall form a bankruptcy remote, special purpose subsidiary ("SPE"), for the sole purpose of holding 100% of the equity shares of BGE. The SPE will have no employees and have no operational functions other than those related to holding BGE shares.

b. The Board of Directors of the SPE will have one independent director. A voluntary petition for bankruptcy by the SPE will require the approval of the entire Board of Directors of the SPE, including
the independent director. The independent director shall be an SPE administration company in the business of protecting SPEs. Any amendment to the organizational documents of the SPE that would remove this requirement or the requirements set forth in 4.e. below also requires the approval of the entire Board of Directors of the SPE, including the independent director.

c. The SPE will issue a non-economic interest (the "Golden Share") in the SPE to an SPE administration company. A voluntary petition for bankruptcy by the SPE will require the affirmative consent of the holder of the Golden Share. The holder of the Golden Share shall be an SPE administration company in the business of protecting SPEs and separate from the SPE [*89] administration company retained for the SPE independent director position. Any amendment to the organizational documents of the SPE that would remove this requirement or the requirements set forth in 4.e. below also requires the affirmative consent of the holder of the Golden Share.

d. CEG will transfer the BGE shares to the SPE as an absolute conveyance or "true sale" with the intention of removing the BGE shares from the bankruptcy estate of CEG.

e. The SPE shall agree to the following:

   i. The SPE's funds shall not be commingled with the funds of BGE or CEG.

   ii. The SPE shall at all times hold itself out as a separate entity from each of BGE and CEG, will conduct business in its own name and will not assume liability for the debts of CEG or BGE.

   iii. The SPE will maintain a separate name from and will not use the trademarks, service marks or other intellectual property of CEG or BGE.

   iv. The SPE will maintain separate books, accounts and financial statements reflecting its separate assets and liabilities.

   v. The SPE will maintain arms-length relationships with CEG and BGE.

   vi. The SPE will have adequate capitalization for the nature of its business.

f. BGE [*90] shall agree to the following:

   i. BGE will not participate in the cash pool operated by CEG and will not commingle funds with CEG.

   ii. BGE will hold itself out as a separate entity from CEG and the SPE, will conduct business in its own name and will not assume liability for future debts of the SPE or CEG.

   iii. BGE will maintain a separate name from and will not use the trademarks, service marks or other intellectual property of the SPE or CEG.

   iv. BGE will maintain separate books, accounts and financial statements reflecting its separate assets and liabilities.

   v. BGE will maintain arms-length relationships with CEG and the SPE.
g. CEG, BGE and the SPE shall obtain a non-consolidation legal opinion from outside counsel to BGE and CEG concluding that a bankruptcy court, following established legal precedent, would not substantively consolidate: (i) the assets and liabilities of the SPE with those of CEG in the event of a CEG bankruptcy; or (ii) the assets and liabilities of BGE with those of (x) the SPE in the event of an SPE bankruptcy or (y) CEG in the event of a CEG bankruptcy. If, for whatever reason, the measures we have defined in this Order do not support an acceptable [*91] opinion letter, CEG and BGE shall take whatever additional measures are necessary to secure this letter;

h. BGE's charter and by-laws shall be amended to include a requirement that the unanimous vote of the Board of Directors of BGE, including the independent directors, is required for BGE to file a voluntary bankruptcy petition.

n148 At the December 1, 2009 status conference, the Companies shall provide a timeline for implementing the ring-fencing measures.

n149 Atkins Rebuttal Testimony at 12-19.

Condition 5: At the same time BGE files its annual ring-fencing report with the Commission, BGE and the SPE shall each file a compliance report with respect to the requirements set forth in paragraphs 4.e. and 4.f., respectively, above.

Condition 6: At the time the SPE is formed and every year thereafter, CEG shall provide the Commission a certificate from an officer of CEG certifying:

a. CEG shall maintain the requisite legal separateness in the corporate reorganization structure;

b. [*92] The reorganization structure serves important business purposes for CEG; and

c. CEG acknowledges that subsequent creditors of BGE may rely upon the separateness of BGE and would be significantly harmed in the event separateness is not maintained and a substantive consolidation of BGE with CEG were to occur.

This last group of measures is purely protective, but critical. Done right, these conditions will separate BGE from CEG for purposes of bankruptcy-protection and credit rating-separation. And when combined with the cash infusion and dividend limitations, BGE should emerge from this Transaction with a stronger financial future that is insulated against being brought down by its parent's riskier, unregulated operations and priorities.

These "no harm" conditions are not intended as a substitute for a comprehensive ring-fencing, cost allocation and corporate governance review of BGE itself. We are prepared to close this proceeding, and not to schedule a Phase III, because we have determined that we can appropriately mitigate the potential harms and risks flowing from the Transaction within the scope of our authority under § 6-105, and because we are confident that we will have [*93] access to the books, records, documents and data from BGE and CEG that we will need to monitor their compliance and BGE's ongoing financial health. n150 Nothing in this Order should be read as a decision not to exercise our general supervisory authority over BGE n151 in the future, or a decision that we will not initiate further supervisory proceedings if and when we find them appropriate.
n150 See PUC § 3-109.
n151 See PUC § 2-113.

IV. CONCLUSION

For the foregoing reasons, we grant EDF's Application and approve the Transaction for closing, subject to the
conditions set forth above.

IT IS, THEREFORE, this 30th day of October, in the year Two Thousand Nine by the Public Service Commission
of Maryland,

ORDERED: (1) That the Application for approval of the Transaction submitted by E.D.F. International S.A. and
EDF Development, Inc. in this proceeding, is hereby granted, subject to conditions [*94] and requirements contained in
this Order;

(2) That through its acceptance of the provisions as a condition to its approval of the Transaction, the Commission
expressly approves the legal isolation of Baltimore Gas and Electric Company from Constellation Energy Group, Inc.
that shall be effectuated by, inter alia, the creation by Constellation Energy Group, Inc. of a bankruptcy-remote, special
purpose subsidiary, which shall be documented as an absolute conveyance or "true sale;"

(3) That E.D.F. International S.A. and EDF Development, Inc. and Constellation Energy Group, Inc. shall notify
the Commission in writing by 5:00 PM, Eastern Standard Time, November 6, 2009, whether the Companies intend to
close the Transaction and, if so, provide the date on which closing will occur; and

(4) That Constellation Energy Group, Inc.; Baltimore Gas and Electric Company; and E.D.F. International S.A. and
EDF Development, Inc. are directed to appear at a status conference on Tuesday, December 1, 2009 at 10:00 AM in the
Commission's 16th Floor Hearing Room, William Donald Schaefer Tower, 6 St. Paul Street, Baltimore, Maryland
21202 to report on the status of the Transaction and the Companies’ [*95] progress toward implementing the
conditions set forth in this Order.

Douglas R. M. Nazarian

Harold D. Williams

Susanne Brogan

Lawrence Brenner

Commissioners

Legal Topics:

For related research and practice materials, see the following legal topics:
Electricity Merger Analysis: Market Screens, Market Definition, and Other Lemmings

Darren Bush

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Abstract  Much discussion and effort have been devoted to the use of market power screens to detect market power that might arise from existing generation asset portfolios or utility acquisition of new generation assets. The quest is to find the “Holy Grail”: a market power detection mechanism that minimizes the costs to all parties involved while finding the majority of market power exercises. This article contends that market power screens should be utilized with caution in policy and litigation applications because while they meet the criteria of minimizing enforcement costs, they are often unable to detect many types of market power exercises that an electric utility might undertake. The article begins with a discussion of the polestar for all screens—the Department of Justice/Federal Trade Commission Horizontal Merger Guidelines—and its limitations. Next, the article examines the accidentally correct, absolutely incorrect, and other outcomes that arise from the application of screens using FERC’s merger policy statement, “contestable load” analysis, and other examples. The Article concludes by noting that many types of market power exercises are undetectable with market power screens, and that better approaches would increase the probability of detection, given the low level of penalty current imposed upon those that wield market power.

1 Introduction

Much discussion and effort have been devoted to the use of market power screens to detect market power that might arise from existing generation asset portfolios or utility acquisition of new generation assets. The quest is to find the “Holy Grail”.

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In this case, the Grail being sought is a market power detection mechanism that minimizes the costs to all parties involved while finding the majority of market power exercises. The expenditures are not trivial. Production of data that might be needed to satisfy an extensive inquiry could be costly in terms of time and money. And the U.S. Federal Energy Regulatory Commission (FERC) could also spend a great deal of time conducting an extensive investigation—time that might be spent examining other industries or other aspects of the electricity industry.

However, the “costs” of investigating market power must be balanced against the costs arising from its exercise. As the California experience demonstrated, market power exercises are costly. For example, interruptions of service in California were costly to businesses and not entirely remedied by FERC’s requirement that some players disgorge ill-gotten gains. Thus, while ex post determinations of such exercises can partially remedy ill-gotten gains, they cannot completely undo the harm caused by exercises of monopoly power to the electricity market and the ripple effects throughout an economy Bush and Mayne (2004).

Because the costs arising from the exercise of market power could exceed the costs that might be incurred in the investigation of such market power, this article contends that screens are not the Holy Grail. Instead, screens should be utilized with caution. Screens meet the criteria of minimizing enforcement costs, but are unable to detect many types of market power exercises that a generation company might undertake. And, absent any probability of detection, a generation company may have an incentive and ability to exercise market power, particularly given the typical penalties received when such exercises are detected and punished.

This article details the foregoing concerns in the pages that follow. It begins by describing some of the idiosyncrasies of electricity markets. Next, it discusses the polestar for all screens advocated in the electricity industry—the Department of Justice (DOJ)/Federal Trade Commission (FTC) Horizontal Merger Guidelines (“Guidelines”)—and its limitations. The article then discusses the Merger Policy Statement promulgated by the FERC (1997b). Next, the article analyzes the flaws that slavish application of screens might create using a comparison of FERC and DOJ enforcement of competition principles in the context of the Exelon/Public Service Electric & Gas (PSEG) merger and the Pacific Enterprises (Pacific)/Enova mergers. The article then addresses other proposed market power screens and their limitations, using “contestable load” and competitive residual demand (CRD) analysis as examples. The article then speculates as to the reasons why FERC and others are on a quest to find a screen that has little benefit in terms of competition policy but could potentially generate great costs. The article concludes that it is insufficient to rely primarily on screens for determining the competitive effects of electricity mergers.


2 While other mergers could be utilized to drive home points made regarding FERC merger analysis, these are the only two cases where there is side-by-side DOJ and FERC analysis of electricity mergers.
2 The Idiosyncrasies of Electricity Markets and Their Impact on Screens

Electricity has unique features that limit the ability of regulators and market monitors to rely on the traditional aspects of competitive markets to promote pro-competitive and pro-consumer outcomes. First, because electricity typically cannot be stored, in the absence of consumer price responsiveness the only market mechanism by which to discipline price is additional capacity available to generate in a particular time period. Second, unlike other commodities, energy generated in one hour of production is not fungible with energy generated in another hour Borenstein (2002), requiring that generation and demand be balanced at all times.

Moreover, due to the minute changes in demand that occur on a regular basis, excess generation capacity must be available to run at a minute’s notice. This reserve capacity is of varying qualities, making some more expensive (and more reliable) than others.

In addition, electricity itself is not a homogeneous product. Specifically, certain generators supply power on a continual basis. These generators are known as “base-load” generation. The generators that supply baseload power are not able to “ramp up” or “ramp down” the power that these units supply to any great degree. Other generators supply power during peak periods of demand. These generators are typically natural gas and oil-fired units and have the ability to “ramp up” or down fairly quickly, assuring that demand and supply are in balance.

Another aspect of the idiosyncratic nature of electricity is that generators located in particular areas are more valuable than others. A generator producing electricity may congest transmission lines and reduce the overall level of generation. Because power flows into cities (where the majority of electricity is consumed), lines delivering power from generators located outside the city can become congested rather rapidly. One way to reduce this congestion is to locate generation within the city limits. Such generation reduces the need to import energy to the city, and also “decongests” the transmission lines delivering power into the city. Particularly because transmission siting is virtually impossible within city limits, generation units within cities become important to maintaining balance between supply and demand.

The importance of promoting generation diversity arises because demand is unresponsive to price due to a lack of price information. The consumer rarely faces the fluctuating real-time prices that accompany constant adjustments in wholesale market.

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3 In actuality, generators are typically called upon to run with ten minute’s notice. For a discussion of reserve markets, see Electric Utility Regulation Committee (2003).

4 Once a generator is running, its power cannot be directed over a particular transmission line; the electricity instead follows the path of least resistance, and thus may flow over numerous transmission lines at once. This creates enormous network problems. A generator brought on to meet additional demand may actually decrease the overall level of generation available to serve demand, as the generator congests transmission lines and blocks out the power of other generators.

5 Nuclear power, coal, “run of river” hydroelectric facilities, solar, and wind are typical baseload sources. However, the output of solar and wind generators are not controllable, and thus they are only intermittently available to provide power.

6 This point can also be made with respect to transactions that wheel power from another area. See Centolella (1996).
equilibria through the hour-ahead market, the day-ahead market, and ancillary services markets. Instead, retail electricity prices are fixed at some (arbitrary) average rate. In this sense, too, demand is relatively inelastic. Consumers—not subject to price increases during peak hours—are not forced to adjust their behavior as supply tightens. Thus, because demand is not responsive, and because demand and supply must be equal at all times throughout the system, excess generation must be available. Another result is a high average price due to the volatility of demand throughout any given day, and extreme peaking prices during times of scarcity.

In addition, because demand does not change when prices change, energy markets rely upon excess capacity from generation sources to discipline price. However, generation sources have different marginal costs because of the physical characteristics of each plant. A generator may use a different fuel type than its next best substitute or, if it uses the same primary fuel, may have different heat rates (i.e., efficiency of converting fuel to energy). Given these different marginal costs, the ability of a generator to discipline the price charged (or the bid) of another generator is limited.

In sum, energy markets have unique characteristics that prevent them from operating like traditional commodity markets. The implications of these idiosyncrasies for electric merger policy are numerous. First, the heterogeneity of supply suggests that market share calculations will not by themselves demonstrate the concentration of the market. Each class of generator is important in its own respects, meaning that market prices could be influenced with only a relatively small portion of the market capacity.

Second, the heterogeneity of units in question in part gives rise to some of the incentives to exercise market power. To the extent that generation companies all seek to diversify their portfolios of assets, each company will likely have generation capacity at numerous points along the supply curve in any relevant market. Many will likely have the same incentives and abilities to influence price during hours in which there is no excess capacity or limited excess capacity.

Third, geographic markets play a crucial role in this industry, perhaps greater than those in the general economy. Geographic constraints are not continuous. They could vary by hour, day, or season. As such, geographic market determinations are much more difficult in this industry than in others.

Fourth, it may not be the case that one can assume a single relevant market. In addition to the capacity and energy markets that may be defined by an Independent System Operator (ISO) or Regional Transmission Organization (RTO), there are potentially products—such as wholesale capacity, wholesale energy, and load-following—that certain customers seek in a bundle. Thus, an examination of the industry-recognized markets may be insufficient.

Fifth, determining whether entry will mitigate anticompetitive conduct cannot strictly be based upon its deconcentrating effect “in the market.” The geographical

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7 Note, however, that aluminum markets may operate like electricity markets due to a supply function in which marginal units have higher costs than “base units. See U.S. Department of Justice (2000a, b).

8 The term “influenced” here refers to prices that are above otherwise competitive levels due to an exercise of market power. The article rejects the term “manipulation” as it is increasingly unclear what precisely the term “manipulation” means. Of course, the same could be said of the term “market power.” See generally Symposium: Creating Competition in Wholesale Power Markets (2005).
location of the generation unit entering the market might be critical, as will its cost of providing energy. Sixth, there are significant vertical issues with respect to generation supply. The most obvious is the abuse of transmission to hamper supply of energy by a competitor in the generation market. A second vertical issue is the use of control over natural gas pipelines or pipeline capacity to increase wholesale electricity prices or preclude entry by a potential competitor. Finally, there are potential retail issues in terms of both horizontal unilateral effects as well as in the retail distribution of electricity to end-users. For these reasons, application of a merger screen to the electricity industry is potentially problematic. The following section examines the two most prominent examples of what might be classified as “market power screens.”

3 Historical Application Market Screens

3.1 The DOJ/FTC Horizontal Merger Guidelines

The Guidelines describe a fairly sound economic methodology for dealing with mergers. First, the Guidelines require a determination of the product and geographic markets in which the merging parties operate. The foundation for the product and geographic market determination is the SSNIP test (“small but significant and nontransitory increase in price”). Starting with the smallest product market possible, the SSNIP test asks whether a hypothetical monopolist could profitably raise price by a small but significant and nontransitory amount. If the question is answered in the negative, then a broader market must be at issue, as consumers flee to available substitutes. The query is then repeated using the next smallest market, until a relevant market is found in which a monopolist could exercise market power. The query is identical for geographic market limitations. Note that market definitions under the Guidelines are driven by the buyer’s reaction to market conditions in the first instance, not an “add ‘em up” approach to calculating the share of capacity that a particular generation owner may possess, which characterizes FERC’s approach under Appendix A of the Policy Statement.

Once product and geographic markets are determined, market shares are calculated for each firm in that market. The Guidelines calculate market shares using “HHIs” (the Herfindahl-Hirschman index), which sums the squared shares of all market participants. The HHI methodology recognizes that disparities in firm size are important considerations in the market share calculation because larger firms have relatively greater “importance in competitive interactions.” For example, other firms may merely follow the behavior of the firm with the greatest market share. Moreover, the Guidelines caution that changing market conditions or markets where substitute products outside the market are not close substitutes may lead to market share calculations inaccurately portraying the competitive conditions that exist within that market.

The Guidelines have two important implications. First, the Guidelines approach to market share calculation has as its purpose the determination of whether a market is concentrated and whether the transaction in question would likely have adverse competitive consequences in that market. In other words, the purpose of the calculation of market share is to determine whether the firms under antitrust scrutiny might
exercise market power. Under the Guidelines approach, if the market is concentrated, then issues such as entry and other factors that mitigate market power are analyzed. If the market is not concentrated, that information allows us to rule out some—though in most electricity markets not all—theories of competitive harm.

Second, a Guidelines approach to market power in industries such as the electric utility industry is really not a market power screen. In light of the HHI calculation, the Guidelines look to both procompetitive and anticompetitive effects arising from a transaction. Moreover, the Guidelines caution against their slavish application, in part because transactions are complex and diverse.

Also, the Guidelines, of course, have difficulty with dealing with vertical issues, as that is not its intended purpose. In the case of vertical issues, the DOJ/FTC in theory apply some portions of the non-horizontal merger Guidelines. However, in greater likelihood, the search is likely for horizontal concentration upstream and/or downstream that gives rise to vertical market power.

An additional issue that until recently was not clarified was the application of a remedy under the Guidelines. However, in October of 2004 the DOJ issued its Policy Guide to Merger Remedies (USDOJ 2004). The Policy Guide lays out what has been viewed as traditional antitrust remedy analysis. Namely, the DOJ prefers structural remedies to conduct-based remedies, seeks to ensure that the divestiture bundle is sufficient such that the buyer can be an effective, long-term competitor, and that conduct remedies be available only in limited circumstances. Finally, as is the case with market power screens, applying the Guidelines slavishly in some circumstances may create misleading answers, as will be discussed in FERC’s application of Appendix A Analysis.

3.2 FERC’s Merger Policy Statement

FERC’s methodology for evaluating mergers is predominantly contained in Appendix A to its Merger Policy Statement (FERC 1997b), referred to as “Appendix A analysis.” The goal of Appendix A analysis, according to FERC, is to “allow the Commission to quickly determine whether a proposed merger presents market power concerns.” Appendix A purportedly accomplishes this task via implementation of the first portions of the DOJ/FTC Guidelines. It is commonly conveyed that FERC wholly adopted the Guidelines. It did not. Instead, it focused almost exclusively on the market definition (in essence pre-determined by FERC and the merger applicants) and market share calculations, steps that are not necessarily conducive to the quick determination of anticompetitive effects arising from a merger but which FERC believed was less intensive than a full blown merger Guidelines analysis.

Appendix A requires the parties to file information concerning relevant product and geographic markets as well as market share calculations. With respect to the relevant product market, Appendix A seeks to identify product overlaps between the merging firms, but typically includes (because they are suggested by FERC) non-firm energy, short-term capacity, and long-term capacity. Peak and off-peak distinctions are

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9 Appendix A uses the term “destination markets.”
also encouraged in Appendix A. Appendix A fails to discuss in any great detail other potential products, instead encouraging the parties to posit additional market definitions “where appropriate.” Such an omission would be appropriate in light of new and emerging markets with different products being offered. However, the problem is that the outcome of the analysis hinges upon this crucial first step, which appears to be left entirely up to the parties seeking to merge.

Next, Appendix A turns to an analysis of customers who might be affected by the merger. FERC assumes that the geographic market includes the merging entities’ service territory and entities directly interconnected to the merging parties. Once the geographic market is identified, FERC includes suppliers in a market “if they could deliver the product to a customer at a cost no greater than 5% above the competitive price to that customer” (FERC 1997a, p. 68596). It could be the case that the SSNIP is less than 5%, of course. But what is potentially more troubling is the process of identifying relevant geographic markets in terms of transmission constraints, which are typically sensitive to which generation plants are in operation, the location of those plants, the load, and a host of other factors. Thus, it could be and typically is the case that the relevant geographic market varies by time of day, season, and demand conditions. Scrutiny of assumptions concerning relevant geographic market then becomes particularly important in electric utility mergers.10

Appendix A analysis then requires a calculation of HHIs, consistent with the Guidelines. In instances in which HHIs exceed the thresholds, the Appendix A suggests that the applicants “then . . . present further analysis . . . .” More important at this stage is that the Commission considers “applicant-proposed remedies.” It is only if no such analysis or proposed mitigation is presented that the Commission examines the merger further, undertaking analysis of anticompetitive effects and whether entry mitigates an anticompetitive effect. In essence, FERC examines competitive effects by assuming them based upon whether or not the screens are exceeded.

Should anticompetitive effects exist, Appendix A outlines potential remedies for such effects.11 If transmission is the issue, Appendix A suggests that requiring transmission expansion or barring the merged entity from trading over constrained paths are appropriate remedies. In instances where market power in generation is an issue, generation plant divestiture is considered an appropriate remedy. Finally, deferring to the mitigation measures of the ISO is suggested as a remedy.

The foregoing appears to be fairly Guidelines-like, with several major exceptions. First, the antitrust enforcement agencies proceed under Guidelines analysis in the first instance, never relying on the merging parties to provide the analysis, only the data. The reason, of course, is that the entire analysis hinges upon how the relevant market is defined, which is incidentally why the relevant market is usually a battle in antitrust litigation.

10 While Appendix A asks for information on constraints, it does not require use of such information in defining relevant markets.

11 Appendix A states that “Although a competitive analysis pursuant to the Guidelines may show that a proposed merger would have anticompetitive effects, the Commission may be able to approve the merger as consistent with the public interest if appropriate mitigation measures can be formulated” (FERC 1997a, p. 68601).
Second, a focus solely on concentration in the first instance rather than effects arising from concentration can yield perverse results with respect to remedy. Thus, in many instances parties seek to duck under the screen triggers by proposing divestitures that drop market shares. This may or may not cure the ill effects of a transaction; such ill-effects are unlikely to be examined in such cases where the parties propose the divestiture of assets. In other words, solutions to problems are proposed and encouraged before anyone knows whether or not there is a problem. Third, use of the screen may cause the FERC to feel bound to it. Thus, the agency may be inclined to fit many square peg mergers into the round holes of the Policy Statement. As will be discussed next, this appears to have been what has happened thus far with mergers with anticompetitive effects not easily described in the horizontal terms of the Guidelines.

3.3 Comparing the Two Approaches

3.3.1 Exelon

The best example, perhaps, of the disconnect between FERC’s use of Appendix A and the competitive harm espoused from a transaction can be seen in the case of Exelon/PSEG. Exelon and PSEG are competitive suppliers of wholesale electricity in the Pennsylvania-New Jersey-Maryland Interconnection (PJM), and in particular eastern and central-east PJM. FERC’s and DOJ’s analysis stand in stark contrast to one another, although both purport to be using roughly the same methodology. The DOJ’s complaint (USDOJ 2006) and competitive impact statement (“statement”) argue essentially a “fuel curve” theory of harm; namely, the diversity of assets within the merged company’s portfolio in the relevant market gave rise to the incentive and ability to raise the price for electricity. The DOJ explained in great detail the basis of its theory of harm in its discussion of relevant markets and market share. The key question was not in this case the relevant product market (wholesale energy), but to what degree the sale of that product was constrained geographically.

DOJ noted that two geographic markets were of importance: PJM East and PJM Central-East. The former is often isolated when five transmission lines become constrained, dividing demand in the northern New Jersey and Philadelphia areas from supply in the rest of the PJM control area, causing prices in PJM East to rise relative to prices in the rest of PJM. The latter constraint is a broader geographic market including PJM East and central Pennsylvania. The boundaries of PJM Central East are defined by two transmission lines. When these two lines are constrained, PJM calls upon additional units east of the constraint to run, causing prices in PJM Central East to rise relative to prices in the rest of PJM.

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12 The terms “theory of harm,” “competitive effects,” and “anticompetitive effects” are used interchangeably in this article.


14 The lines are unlovingly named “5005” and “5004.”
The DOJ’s statement next discusses what is lacking in FERC’s analysis of the merger—a theory of harm. Prior to discussing market shares, the competitive impact statement explains that:

in both geographic markets the merged firm would own low-cost baseload units that provide incentive to raise prices, mid-merit units that provide incentive and ability to raise prices, and certain peaking units that provide additional ability to raise prices in times of high demand (USDOJ 2006, p. 6).

Fuel curve theories occasionally mesh well with high market shares, as in this case. The post merger HHIs were 2,750 in PJM East and 2,080 in PJM Central East, with merger-induced increases in both cases of over 700 HHI points. However, it is not necessarily the case that high market shares will coincide with a fuel curve theory of harm. Conversely, it is not necessarily the case that a reduction in market concentration level, by itself, will mitigate the harm.

But the DOJ’s statement does not stop at market shares, highlighting the increased incentive and ability of the combined firm to wield its marginal and mid-merit units in a fashion that would benefit its infra-marginal baseload and mid-merit units. The statement also describes how entry would not be timely in mitigating the increased incentive and ability to wield market power brought about by the transaction.

The DOJ’s remedy aligned well with the competitive harm it found by requiring divestiture of specific marginal units that are close to and potentially could set the clearing prices in the relevant markets for a substantial number of hours. Thus, the DOJ remedy eliminated the ability of the combined firm to raise prices profitably. While the statement makes much of the deconcentrating effect of the proposed divestiture, the fact that specific units were targeted for divestment suggests that the dominant issue was not market shares per se but the conduct that increased market power could yield.

In contrast, FERC’s analysis (FERC 2005) of the merger appears targeted solely at market shares and the effects of deconcentration without regard for the conduct at issue.

FERC—apparently relying solely on the analysis provided by the merger parties’ experts—noted substantial increases in concentration in all relevant markets analyzed. For example, in PJM-East, one of the merger applicants’ economic witnesses (Dr. Heironymus) testified that the HHIs were between 2,057 to 2,492, with deltas (changes in seller concentration caused by the proposed merger) above 800 HHI points in energy markets, with mirroring effects in capacity markets. Dr. Heironymus found the other markets he analyzed to be moderately concentrated with deltas over

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15 Baseload generation units are units that are dispatched any time that they are in operation. They typically have low marginal costs and do not typically set the clearing price in electricity markets. Historically, these plants have been coal, nuclear, wind, and hydro. In contrast, peaking generators usually operate only during peak demand periods and can be brought online very quickly, although their variable costs are too high to warrant operation during off-peak periods. These units typically set the price in most hours in electricity markets. Mid-merit units fall between these two extremes, having typically mid-level marginal costs but not setting the price in electricity markets when demand is highest. Examples of such plants include combined cycle natural gas plants.
100 HHI points. Dr. Frame, another testifying expert for the merging parties, offered analysis consistent with Dr. Heironymus.

Based upon their analysis of the relevant market, FERC proceeded to examine whether or not the parties’ proposed mitigation adequately addressed the effects of the proposed merger. It is important to note that the parties did not address any behavioral consequences of the merger, but rather focused on whether or not the proposed mitigation sufficiently deconcentrated the market so as not to trip FERC’s market screens. Thus, the parties proposed to “virtually” divest themselves of 6,600 MW of generating capacity. The divestiture scheme involved 2,450 MW of nuclear generation, with all but 200 MW of it being in PJM-East. The remainder included mid-merit and peaking capacity in PJM-East. Other mitigation measures included bidding all capacity into the daily market at a price of zero.

The trouble with the proposed mitigation in the FERC Exelon/PSEG case is manifold. First, the definition of the relevant market and market share analysis is unlikely to detect market power. The utilization of a group of smaller marginal generators to raise price is not likely to trigger market share concerns, but does affect the prices paid to generators in the entire market. Second, it is not clear what the purpose of the mitigation is, apart from reducing the sheer size of the transaction (and therefore the HHIs). The divestiture of generation assets may deconcentrate the market, but may not eliminate market power. This highlights a tension between the Guidelines and the “heterogeneity” of assets providing what appears at first blush to be a homogenous product. Thus, with respect to a “fuel curve” theory of harm, deconcentration may not eliminate any of the firm’s ability to withhold marginal units that set the clearing price paid to inframarginal units. In other words, deconcentration may decrease the merged firm’s incentive to use marginal plants to increase prices, but doesn’t eliminate either the firm’s incentive or its ability to do so.

As an example, suppose that Utility A purchased a baseload generation plant conferring upon it a 20 percent market share in the relevant market. It then purchases in a subsequent auction peaking facilities, increasing its market share by 5 percent. Assume further that Utility A is the largest player in the market. Under a strict reading of the Guidelines and under FERC’s Appendix A analysis, there would be no challenge, because the market share is sufficiently low in the relevant market and the transaction does not dramatically increase it.

However, such a purchase may very well have anticompetitive effects. For example, suppose that Utility A’s peaking units set the price in most hours. Utility A may know that its unit is typically called upon and thus may bid that unit higher (i.e., economic withholding) or have an “accident” that causes the plant to be physically withheld. As a result, the next highest cost plant is selected, causing prices in the market to increase. Under a screen analysis, such an effect is indeterminable unless one does the extra hard work of looking at where market power could actually be wielded and articulating a theory of harm. Thus, defining the relevant market cannot be done in a vacuum. A pre-analytic vision of what harms might arise from a transaction is necessary, followed by determining whether a relevant market exists in which such harms might occur.

Other components of the FERC remedy create more questions than they answer. For example,
Under virtual divestiture, the ownership and control of nuclear capacity would be retained by the merged company while it sells (or swaps) the energy to third-party purchasers. Sales or swaps would occur through a variety of contractual mechanisms, to unspecified buyers, for differing contract lengths, and under unseen terms and conditions. This marked lack of specificity regarding the structure of the energy contracts creates a “black box” into which these 2,600 MW will go and only the merged company will have insight into its internal workings (Moss 2005).

As Dr. Moss suggests, the important question is whether the remedy gives rise to some coordinated behavior or effects between the contracting parties as a result of the energy swap. The swap may not, in fact, eliminate any market power, depending upon the incentives of those who own the energy. Thus, it is insufficient to proclaim that the remedy will be the antidote to some unspecified poison. Rather, it is important to determine the poison before attempting to render the antidote(s).

The proposed bidding of capacity at a zero price is similarly troublesome. Assuming that the issue is fuel curve related, there is still the risk that physical withholding might occur given the incentive and ability to wield market power using marginal capacity. Of course, physical withholding might be easier to detect than economic withholding, but there are still issues of oversight and monitoring that make this remedy less efficient than the structural remedy proposed by the DOJ. Moreover, the requirement that Exelon bid some generators at zero may not help if Exelon can bid other capacity at higher prices. Such a cap is potentially inefficient for other reasons, such as promoting dispatch of the price-capped unit to the detriment of more efficient units.

3.3.2 PE/Enova

The preceding discussion of Exelon/PSEG is not to state, however, that FERC has never engaged in the hard work of relevant market analysis that focuses upon competitive effects, forgoing the deceptive “ease” of market screens. For example, FERC has ignored the screen mantra in at least one vertical case. In Pacific/Enova, FERC’s analysis (FERC 1997a) appears more in line with the DOJ’s analysis of the transaction. Here, the theory of harm alleged by the DOJ is virtually identical to that alleged in Exelon, except that the means by which prices would be raised in the electricity market was not direct ownership of generation assets that set the price in the market during certain hours, but rather supply of natural gas input to those units.

Pacific’s subsidiary Southern California Gas Company (SoCalGas) was virtually the only provider of natural gas transportation and storage services to gas-fired electricity plants in Southern California. According to the DOJ complaint (USDOJ 1998),

16 SoCalGas received a “Hinshaw” exemption under the Natural Gas Act, making it a monopoly intra-state pipeline. The Hinshaw exemption provides that regulation under the Natural Gas Act shall not apply to:

any person engaged in or legally authorized to engage in the transportation in interstate commerce or the sale in interstate commerce for resale, of natural gas, received by such person from another person within or at the boundary of a State if all the natural gas so received is ultimately consumed within such state, or to any facilities used by such person for such
these plants operated 30–50 percent of the time in California and set prices for all electricity sold in the California market during peak times. Enova owned and operated baseload generation plants for the supply of electricity in California; namely nuclear, coal, certain gas units, and hydroelectric plants.

The DOJ argued that the combination of the assets would give the merged firm the ability and incentive to raise the price of electricity in the California electricity market. The incentive for such an increase derived from Enova’s ownership of infra-marginal units. And, as the DOJ also noted, entry into the electricity market could not mitigate the harm from the transaction as it would likely be from gas-fired units reliant upon gas transportation and storage. FERC similarly recognized the vertical aspects of the transaction, and treated it as a vertical merger. FERC first noted the (in)applicability of its Policy Statement:

[A]lthough the same general factors that govern our analysis under the Merger Policy Statement apply here, the Merger Policy Statement originally was crafted to apply primarily to horizontal mergers. The Commission’s approach to evaluating the competitive effects of vertical mergers is evolving as the Commission gains more experience with the convergence of gas and electric utilities. Additional experience will undoubtedly bring new insights to bear in refining our analysis (FERC 1997a, p. 62560).

The Commission, however, did not reject the Policy Statement entirely. Instead, FERC described it as

[A]s a starting point to evaluating the competitive effects of the proposed transaction. . .applied to both the upstream delivered gas and downstream wholesale power markets to determine whether those markets are conducive to the exercise of market power after the merger (FERC 1997b, p. 62561).

At first blush, the Commission’s statements appear at odds with one another. But in reality FERC recognized the horizontal implications of vertical acquisitions (i.e., that most vertical issues arise from an exercise of horizontal market power). Thus, the analysis should proceed, albeit unslavishly, as would a horizontal merger, requiring market definition and the analysis of competitive conditions in both the upstream and downstream markets, including entry and the effect that the acquisition would have on competition in those markets.

Taking this approach, FERC analyzed the effects of the acquisition in the relevant downstream energy market and upstream gas market in Southern California. Defining Southern California as the relevant geographic market recognized the transmission limitations between northern and southern California. Within this context, FERC noted that SoCalGas held approximately a 96 percent market share in the delivery of gas to gas-fired steam and combined-cycle generators. Based upon this market share, FERC concluded that the combined firm could wield its market power over gas to frustrate the

Footnote 16 continued
transportation or sale, provided that the rates and services of such person and facilities be subject to regulation by a state Commission. 15 U.S.C. Sect. 717(c).
access to gas of the combined firm’s rival generators. Because of SoCalGas’ monopoly position, competing generators in the Southern California area would not be able to switch to alternative gas suppliers.

However, the description of the harm in FERC’s Order appears as a raising rival’s cost argument. Ninety-six percent of gas fired capacity in California was supplied by SoCalGas. It proceeded to do something that appears awkward under its Merger Policy Statement. FERC crafted a relevant market composed of economic generating capacity whose variable cost is equal to or less than 5 percent above the cost of gas-fired steam generation. Within this market, approximately 60 percent of generating capacity that “can potentially supply energy from economic capacity” received gas from Southern California Gas Company. It then proceeded to craft a market concentration measure statistically “analogous” to the HHI. Under the measure, FERC considered all of the generating capacity supplied by Southern California Gas Company as controlled by one entity, leading to an “HHI” of over 1,800. Thus, after the merger, “higher delivered gas costs to generators served by SoCalGas would likely result in higher wholesale electricity prices.”

FERC’s analysis leads it to the same conclusion as the DOJ’s analysis: “Circumstances in the upstream delivered gas and downstream wholesale electricity markets indicate that the merged company could potentially raise input costs to competing generators, therefore resulting in higher wholesale prices” (FERC 1997, p. 62563). FERC imposed conduct-based remedies designed to bifurcate the merged firm. SoCalGas was required not to disclose information arising from gas sales to its sister company, San Diego Gas & Electric. Concerning SDG&E’s competitors, FERC imposed rules that sought to thwart discrimination against those same competitors, and electronically post gas prices and pipeline capacity in real time. In other words, FERC relied upon its traditional tools of open access, firewalls, and mandates against discrimination.

In contrast, the DOJ required the combined firm to sell all of its “low-cost generators” in an effort to eliminate any incentive to raise prices. Thus, the proposed final judgment required the sale of 1644 MW of baseload generation that operated in “almost all hours of the year and are relatively low-cost” (USDOJ (1998), p. 9). As such, these units would benefit from any increase in the post-merger price of electricity resulting from the combined firm’s manipulation of its gas assets.

3.3.3 Lessons from the Comparison

At least three lessons can be gleaned from the foregoing comparison of the DOJ’s and FERC’s take on merger analysis. First, for the DOJ, the theory of harm is intertwined with the definition of the relevant market – albeit, it is a bit nuanced. The two cases raised above deal with issues that are vertical or “vertical-like” in nature. The Exelon/PSEG case is a relatively simpler matter as the HHIs bore out the theory of harm, although this is more coincidental than a necessity of the theory. However, it is entirely possible that HHIs would be minimal and yet harm could result from a potential transaction. Recognizing this, DOJ not only included a discussion of market shares in its statement but also linked the relevant market to the theory of harm. In contrast, FERC relied on HHIs to yield fruitful results.
Second, the remedy was directly related to the theory of harm espoused by the DOJ. Thus, specific generation units were targeted for divestiture due to their ability or incentive to exercise market power. The DOJ remedy thus had as its goal the elimination of the ability and/or incentive to exercise monopoly power. In contrast, FERC appeared focused on the deconcentrating effects of a virtual divestiture that would have required a substantial degree of regulatory oversight. However, it was entirely unclear whether market deconcentration would have mitigated any of DOJ’s concerns about fuel curve opportunities. If so, it is likely that the cure would have been happenstance. In Pacific/Enova, the remedy was much more in line with the theory of harm espoused by both the DOJ. As discussed below, there may be good reasons why there was greater analytic rigor employed by FERC in this earlier case than in the Exelon/PSEG case. FERC’s approach would deem any divestiture acceptable because it would be deconcentrating while DOJ’s approach required specific kinds of units to be divested.

Third, the remedies relied upon by DOJ tend to be structural in nature. DOJ lacks the ability and the desire to become a second electricity regulator. To do so would not only require the DOJ to become a quasi-administrator, but also could potentially require a judge to be a willing administrator as well. Since Judge Greene’s role as a virtual regulator of the telecommunications industry in the 1980s, judges are increasingly reluctant to play the role of regulator. Thus, even if DOJ wanted to impose conduct remedies, they would lack the means by which to do so. Even this is unlikely. Structural remedies are infinitely cleaner. There is a set, short time frame for divestiture of assets and typically some prohibitions on re-acquisition of assets.

Structural divestitures do not require the same degree of oversight as virtual divestitures or other conduct-based remedies. Thus, structural remedies are tremendously more efficient from an enforcement perspective than are conduct remedies. As the DOJ Remedies Policy Guide (Policy Guide) suggests:

Structural remedies are preferred to conduct remedies in merger cases because they are relatively clean and certain, and generally avoid costly government entanglement in the market. A carefully crafted divestiture decree is “simple, relatively easy to administer, and sure” to preserve competition. A conduct remedy, on the other hand, typically is more difficult to craft, more cumbersome and costly to administer, and easier than a structural remedy to circumvent (USDOJ 2004, Sec. 3.1).

Moreover, the Policy Guide continues, there are costs associated with monitoring compliance with the remedy. The merged firm may attempt to evade regulation, leading to indirect costs associated with such evasion. Conduct remedies may also restrain pro-competitive behavior and paralyze the subject of the conduct remedy such that it cannot respond to changing market conditions. Nonetheless, FERC tends to rely on conduct based remedies. While it is not clear that FERC has any greater ability to police violations of conduct remedies than would the DOJ, FERC may have the perception that it is capable of doing so.

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4 Other Attempts at Screens

The limitations of FERC’s merger analysis has caused some to attempt to provide FERC with a modified screen to more effectively separate anticompetitive “wheat” from pro-competitive “chaff.” Below are two examples of potential screens that could be employed by FERC as a substitute for Appendix A analysis or perhaps as a complement to it. Regardless, there are issues patent in these approaches that give rise to difficulties latent in Appendix A analysis and with any merger screen that is indiscriminately employed.

4.1 Contestable Load

One potential merger screen is the “historical contestable load analysis” advocated by Jahn (2005) on behalf of the Edison Electric Institute (EEI) as a screen for determining market-based rate eligibility. While the analysis requires multiple steps, the key one involves limiting the competitive assessment of the market to a comparison of loads “shopping” for an electricity product to the number of megawatts available to supply each product. The EEI approach would require applicants, using the most recently available historical data, to (1) identify relevant geographic markets; (2) identify relevant product markets; (3) identify all “contestable loads” (i.e., loads subject to competition), by product for “the historical test period;” (4) identify all potential competitive generation suppliers in the designated markets; (5) determine the total uncommitted wholesale capacity that would have been available during these historical periods to compete for load; (6) determine whether suppliers from outside the market could have provided capacity; and (7) calculate the ratio of competitive generation to contestable load, by product and season, during the “historical period.” If the “if total competitive generation resources are at least twice the total contestable load, the applicant will be deemed to have passed the analysis for the specified product and seasons” (Jahn 2005, pp. 7–8).

A variant on the contestable load analysis, offered to FERC by American Electric Power (AEP) and called the “truncated market share analysis,” seeks to “account for demand” in the calculation of market shares (AEP 2004, p. 8). Doing so—advocates of this methodology claim—ensures that “anomalous results” do not occur in the calculation of market shares. One specific example is illustrative:

Consider the situation where a market has ten suppliers, each with 100 MW of uncommitted generation capacity. The market share analysis would give each supplier a 10 percent share and all would pass the screen. Now, assume there is an identical market where there is an additional generation supplier with a 1,000 MW unit. This additional supplier has 50 percent of in-area generation in the second market, and the other supplier’s shares drop to 5 percent. Although, as a general rule, an additional supplier makes a market more competitive, not less, the result under the market share test indicates a problem as a result of the presence of the additional supplier in the second market. What is missing, and what causes an anomalous result under the market share test, is some measure of demand in the market (AEP 2004, p. 8).
The way to account for load, proponents argue, is to determine the amount of load that can “shop” for power. The analysis then turns back to the generators and determines whether each generator can provide all of the load’s needs. If each generator can meet all of the needs of the load, then market shares would be assigned pro rata to each of the suppliers in the market. In the quoted second example above, market shares would be nine percent. Thus, the allocation of pro rata market shares purports to solve the problem of “anomalous results” in the sense that the dominant firm in this market cannot wield all of its capacity in the exercise of market power. Purportedly, support for the proposition that market shares should be allocated pro rata for suppliers able to meet the needs of the contestable load is found in a footnote in Section 1.41 of the Guidelines.18

There are numerous difficulties with the assumptions underlying contestable load analysis, which appear at first blush to be quite reasonable.

4.1.1 Conflicts with Standard Competition Analysis

Contestable load analysis as portrayed by AEP, Jahn, and others runs counter to standard competition analysis (as reflected in the Guidelines, for example) that the antitrust enforcement agencies employ. Specifically, the agencies seek to determine whether, under any theory of competitive harm, the combined firm’s market share will give rise to anticompetitive effects that result in consumer injury. Only after this analysis is undertaken do the Guidelines seek to examine the combination’s redeeming or mitigating factors such as entry, efficiencies, or excess that mitigates market power. Moreover, the assumptions under which Footnote 15 is employed do not hold in the electric utility industry. The approach also raises issues as to how relevant markets are defined in electricity and where customers can practically turn to for supplies. In sum, FERC should not adopt this approach.

One limitation of the contestable load analysis is that it ignores differences among potential suppliers of products. In particular, buyers may seek to purchase multiple products from what are typically not homogenous suppliers. Such products include capacity, energy, load-following service, and the like. It is possible that some generation assets are able to provide all of these products but others are unable to do so.19 In such a situation, it cannot be said that merely because a generator owns an

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18 Footnote 15 states that, “when all firms have, on a forward-looking basis, an equal likelihood of securing sales, the Agency will assign firms equal shares.”
19 The effect of supply portfolios on a firm’s ability to compete is evident in the marketplace. The fleet of a dominant seller allows it to compete for a wider variety of products, whether load-following type contracts or firm capacity sales.12 Sellers with these capabilities can economically add a new 25 MW wholesale load (backed by reserves) to their existing load obligations, providing both firm power and load-following type services. By contrast, if an IPP has just a single plant, it may have trouble “firming up” the sale to ensure deliveries at times of plant outages. Further, an IPP with a single, 500 MW combined cycle plant often can’t make a 25 MW unit capacity sale unless it has an “anchor tenant” to purchase the bulk of its plant output and ensure efficient plant operation. The 25 MW sale will not be a viable option. The IPP is also unlikely to be in a position to provide a load-following type service and is subject to substantial energy imbalance penalties under the Order No. 888 Open Access Transmission Tariffs (“OATTs”) that the dominant seller with its own control area (usually the transmission provider) doesn’t have to worry about (APPA and TAPS 2005, p. 12).
asset that could provide some of the buyer’s needs (e.g., energy) that it necessarily is a competitor to a generation owner that is able to supply all of these products (e.g., load-following service). Rather, it is the bundle of products that the buyer may seek. The buyer, in seeking to purchase these products, will take offers from firms that can provide them. Thus, buyers could only turn to a subset of the firms that would be included in either the AEP or EEI contestable market analysis for supply. This difficulty potentially arises in any merger screen, if one is not careful about the relevant product market definition and merely counts up megawatts units.

The EEI contestable load analysis ignores the question that drives market definition analysis under the Guidelines. Specifically, the market definition portion of the Guidelines “focuses solely on demand substitution factors—i.e., possible consumer responses.” In order to determine to whom the customers might turn for supplies of these multiple products, antitrust enforcers would typically ask the consumer to answer these questions, not the supplier. “Supply substitution factors—i.e., possible production responses—are considered elsewhere in the Guidelines.” However, it appears that the contestable load analysis gets it exactly backwards. The EEI analysis requires identification of the “all loads within the relevant market that were actually subject to competition (contestable loads)” (Jahn 2005, p.6, emphasis added), but only after relevant markets have been identified from the perspective of a supplier looking at which market it can sell its product and who else is selling it. Under the EEI analysis, it would be difficult for an antitrust investigator to unearth whether buyers were subject to market power by a small number of firms that were offering the full range of products that the buyer seeks.

4.1.2 Emphasis on Market Shares

A second problem with contestable load analysis can be explained in the context of the relationship of relevant market definitions and market shares to the remainder of the Guidelines factors. The whole point of the Guidelines’ approach to market definition is to ascertain the level of concentration in the market for the purpose of determining whether the merger will harm competition. Should the market prove concentrated, then the transaction requires further analysis to determine the extent to which concentration is a problem. If the market is unconcentrated, then perhaps no further analysis is necessary. However, these are not hard and fast rules. As the Guidelines point out, those who slavishly apply the Guidelines do so at their own peril. The crucial point is that market shares are the beginning of the analysis, not the end. It is only after the determination of whether the industry is concentrated or not that a decision is made

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20 Horizontal Merger Guidelines, Sect. 1.0.
21 Id.
22 Guidelines at Sect. 0. “Because the specific standards set forth in the Guidelines must be applied to a broad range of possible factual circumstances, mechanical application of those standards may provide misleading answers to the economic questions raised under the antitrust laws. Moreover, information is often incomplete and the picture of competitive conditions that develops from historical evidence may provide an incomplete answer to the forward-looking inquiry of the Guidelines. Therefore, the Agency will apply the standards of the Guidelines reasonably and flexibly to the particular facts and circumstances of each proposed merger.”
as to whether further analysis should be undertaken. As has been discussed earlier, improper market definition can yield a false negative in a market share screen, meaning that an anticompetitive merger could potentially fall through the cracks.

Calculations of market share serve a particularly important role in providing enforcement agencies with insights into a market—insights that would be lost under a contestable load approach. First, the Guidelines’ method of calculating market shares (i.e., HHIs) recognizes that differences in the relative size of the market participants matter. Concentration measures utilized prior to the adoption of the HHI methodology did not account for the presence of dominant firms in a market. In contrast, HHIs explicitly recognize that size disparities between firms may lead to heightened market power—firms may merely follow the behavior of the firm with the greatest market share, for example. The contestable load analysis, however, misses the whole point of calculating HHIs in the first place. As EEI proposes it, the dominant firm drops out of the picture altogether. As AEP proposes it, competitors are treated as the same size.

Another important component of the Guidelines approach to market share calculation is the focus on the merging parties (in merger cases) or the firm whose conduct is alleged to violate Section 2 of the Sherman Act (as monopolization or an attempt to monopolize in non-merger cases). The focus is on the firms that are of the most competitive concern because anticompetitive effects/pro-competitive benefits often arises from their conduct. In other words, the purpose of the calculation of market share is to determine whether the firms under antitrust scrutiny might exercise market power. It is typically not the mouse frolicking across the competitive field that is the problem, but rather the elephant undauntedly stomping everything in its path that the Guidelines seek to examine. By ignoring the disparate roles of the firms in question and compiling only aggregate (and therefore poor) indicators of a market’s competitiveness, EEI’s approach to market analysis would not prove useful in detecting, preventing, and restraining exercises of market power.

Moreover, contestable load analysis finds no support in the Guidelines. Proponents of the AEP version of contestable load analysis point to Guidelines Section 1.41. As one of the Guideline’s authors points out, the “one-over-n market” approach is useful when the market in question has “two essential characteristics:”

23 An example from my antitrust course is helpful. In Industry X, suppose there are five equally sized firm, each controlling 20 percent of the market. $20^2 + 20^2 + 20^2 + 20^2 + 20^2 = 2000$ HHI. In Industry Y, suppose there is one firm with 60% of the market, and the rest are relatively small. $60^2 + 10^2 + 5^2 + 5^2 + 5^2 + 5^2 + 5^2 = 3850$ HHI. A traditional measure of concentration (the four-firm concentration ratio known as “CR4”) would indicate that the first market is equally as troublesome as the second (CR4 would equal 80 in both). The HHI, however, indicates that the second market is far more troublesome.

24 While Jahn (2005, p. 8) purports to examine concentration among the competitive suppliers, such an examination would be meaningless because it leaves out the firm whose market power potential is the subject of the inquiry.

25 Footnote 15 describes a “one-over-n market” in which market shares are assigned equally to all sellers in the market when “all firms have, on a forward looking basis, an equal likelihood of securing sales.” Guidelines Section 1.41 n. 15. Examples of such markets include “markets for technologies or innovation and Schumpetarian industries, in which competition occurs largely through the introduction of new products or technologies and competition is apt to be more ‘for the market’ than ‘in the market’” (Werden 2002, p. 67). While not limited solely to intangible goods, the “one over n market’ approach has in fact been quite limited in application. For a rare glimpse at the analysis, see USDOJ (2000).
(1) a finite number of entities possess a readily identifiable set of assets essential for successful competition; and (2) the extent of ownership or control over the essential assets does not distinguish among these entities in any important way. In the clearest case, all competitors have the same costs, and each can supply the entire market demand (Werden 2002, p. 86).

Dr. Werden’s discussion of the “one-over-n market” takes place in a section titled “market shares based upon intangible assets” and is essentially a discussion of auction markets. In contrast, Dr. Werden’s discussion of electricity takes place in a section titled “capacity-based market shares.” In that section, he notes that there is substantial cost heterogeneity across generation units, in part due to the type of facility (base-load as opposed to peaking), but also due to “differences in fuel choice and unit age” (Werden 2002, p. 84). Both the AEP and the EEI forms of contestable load analysis ignore this heterogeneity.

Thus far, it should be clear that the analysis undertaken in the Guidelines is in the first instance a determination of the potential for anticompetitive conduct given the structure and concentration in a particular market. Specifically, market share calculations are useful tools to determine whether further analysis is warranted. If the market is concentrated, then issues such as entry and other factors that mitigate market power are analyzed. If the market is not concentrated, it allows us to rule out some, though in most electricity markets not all, competitive effects theories. However, entry that mitigates market power and other factors are not employed in the market definition or market share analysis.

For example, Section 2.22 of the Guidelines deals with firms “Distinguished Primarily by Capacity.” The section discusses firms that offer relatively undifferentiated products in an industry in which capacity “shapes the nature of their competition.” The Guidelines in this section look to the competitive effects in such markets, and whether there is any reason that concentration in such markets might be problematic.

This issue is raised not because it ought necessarily apply to electricity markets, but to emphasize that issues of excess capacity and entry that mitigate market power are analyzed only after the relevant markets are defined and market shares calculated. The potential that excess capacity or entry may discipline price is not addressed by contriving pro rata market shares. Doing so thwarts the whole purpose of calculating those shares, and yields no meaningful information as to any potential factors that either mitigate market power or incent its exercise. In fact, contestable load analysis dispenses with both structural and effects analysis, instead favoring an “add ‘em up” approach of calculating market shares for only the capacity that is excess to the supplier’s own when it is the supplier’s own capacity that is of interest. The end result is

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26 The Guidelines provide for identification of existing firms that “participate in the relevant market,” including “uncommitted entrants” (other firms “not currently producing or selling the relevant product in the relevant area” but whose inclusion “would more accurately reflect probable supply responses.”) Guidelines at Sects. 1.31–1.32. Entry is considered for different purposes in Section 3.0 of the Guidelines to determine whether such entry would prevent “market participants, after the merger, either collectively or unilaterally” from profitably maintaining “a price increase above pre-merger levels.” Id. at Sect. 3.0 For a discussion of all the roles entry might play in antitrust cases, see Bush and Massa (2004).

27 Guidelines at Sect. 2.22.
to forgo the hard work of determining whether a firm has the incentive and ability to exercise market power.

In sum, a Guidelines approach to market power in industries such as electricity differs dramatically from the contestable load approach. Market definitions under the Guidelines are driven by the buyer’s reaction to market conditions. Market shares are calculated without reassigning them based upon potentially mitigating factors such as excess capacity. In light of the HHI calculation, the Guidelines look to both procompetitive and anticompetitive effects arising from a transaction. In contrast, the contestable load analyses of EEI and AEP both base market shares not upon markets determined out of buyer reaction, but on markets contrived by the seller. The two approaches also ignore the important step of analyzing competitive effects that could arise from such concentration, whether procompetitive or not.

While the purported goal of the contestable load analysis is to avoid “false positives” in the detection of market power, it is clear that the pendulum has swung back completely and has created a theory whereby, through flawed screens, FERC would be awash in “false negatives,” as firms file under a rudimentary contestable load screen—a screen that ignores the complexity of the market analysis necessary in budding energy markets.

4.2 Competitive Residual Demand Analysis (CRD)

Gilbert and Newbery’s (2008) CRD analysis appears as an analog to contestable load analysis. CRD analysis examines the residual demand facing the merging firms in both the pre and post merger period to determine whether the combined firm has the ability to exercise market power. According to the authors, residual demand is “the wholesale market demand less the aggregate uncommitted supply from all other firms, computed at each price chosen by the merging firms.” Demand in this case is assumed to be inelastic and thus independent of prices. However, demand will vary temporally as a function of weather and other such conditions. Residual demand facing the merged firm is also a function of the supply provided by competing firms. The authors assume that the market supply is competitive, which they note is not “unreasonable when other firms are small and are unlikely to have significant market power.”

The benefits of the analysis, according to the authors, are that it is easier to calculate than a full equilibrium analysis. Second, it is sufficiently flexible to accommodate different demand conditions (say, upon seasonality) as well as different geographic market assumptions. The authors also note the deficiencies of CRD analysis: in particular, its inability to examine coordinated effects or examine the supply reaction to any first-stage post-merger increase in price.

The effort is laudable. Unlike the proponents of contestable load, the authors do not proclaim it to be a Guidelines analysis. Instead, the authors appear to recognize the limitations of their approach as well as any screen approach to merger analysis. For example, the authors recognize that CRD is unable to address any sort of coordinated effects story, thus foreclosing any analysis of at least one theory of harm. In addition, much like with contestable load, there is the issue of whether there is a bundle of products that customers require together. In a straight capacity-based analysis, such issues
are not likely to be discovered. In addition, to determine the geographic boundaries of
the market, one must determine transmission constraints and other barriers to bringing
supply to customers.

Thus, the hard work of defining relevant markets is not displaced by CRD analysis.
Moreover the authors recognize that CRD analysis, even if implemented, cannot be
the end-all of the story. Suppose CRD analysis finds serious post-merger price effects.
The obvious next question is whether there is a supply response that would mitigate
the market power being employed, which CRD analysis is not particularly well suited
to answering. Of course, these latter points do not mean that CRD analysis could not
be employed, but rather would need to be supplemented.

If one were being slavish to the Guidelines, one could not employ CRD analysis to
determine the relevant market. This is because, as the authors point out, that “competi-
tive residual demand analysis may understate the likely equilibrium post-merger price,
because it does not take into account a possible reaction by all other firms to higher
prices by the merged firms.” Thus, it appears that CRD cannot be used to implement
any sort of SSNIP test, nor does it appear to be intended for that purpose.

There are limited uses to any merger screen. It is at best an imperfect device that
does not address many of the questions that necessarily require answers in determining
whether a merger is, on balance, anticompetitive. The CRD analysis may be the best of
the merger screens proposed to FERC, and could prove useful until the time at which
FERC returns to doing the very hard work of full-scale merger analysis.

5 Why the Need for a Screen?

If screens are problematic for antitrust enforcement purposes, the question becomes:
What purpose does the screen serve? In general terms, a screen is an imperfect device
designed to catch larger objects while allowing smaller ones to pass through. The ben-
efit of the screen is that it rapidly eliminates individual sorting of whatever particles
are of value from those that are valueless. Of course, the greater the size of the holes
in the screen the more rapid the screening process, but the greater the likelihood that
one will lose valuable material along with the valueless. The smaller the holes, the
slower the process becomes. So too is the case with merger screens. In antitrust terms,
the goal is to separate efficiently the anticompetitive merger from the pro-competitive
one. The value of a merger screen to FERC, if there is one, is that it allows FERC to
dispose of the merger in rapid fashion. However, the costs of such a screen involve
both the possibilities that the screen will trip up otherwise competitive mergers (the
problem of false positives) while unleashing some anticompetitive ones (the problem
of false negatives).

This usual discussion of “Type I” and “Type II” errors that accompany discus-
sions of merger screens is an anathema to those steeped in traditional antitrust merger
analysis. Granted, developing theories of harm, defining relevant markets, examining
concentration, competitive effects, entry and efficiencies can yield Type I and Type II
errors, but it does so to a lesser degree given the greater degree of scrutiny devoted
to the transaction. The gaps in FERC’s merger screen have been discussed above and
elsewhere and need not be repeated. Instead, one question is why FERC is clinging to
Appendix A even in instances where it has limited applicability and why others seek to provide tools to enhance the benefits of such a screen.

One answer to the question lies largely in ideology surrounding remedies. FERC’s merger policy is largely based upon jurisdictional oversight. FERC imposes remedies that are not crafted to eliminate the anticompetitive condition arising from the merger but instead seek to regulate it. In contrast, DOJ merger remedies are inherently skeptical of regulatory solutions, instead seeking to reduce or eliminate anticompetitive incentive and/or ability. Clinging to Appendix A allows FERC a discrete set of potential remedies, typically proposed by the parties who are cognizant of their screen violation well in advance of filing at FERC.

FERC’s recent passivity towards remedies applies also to the investigation of the transaction. It appears that FERC increasingly relies upon data submitted by the parties, eschewing utilizing its own economists and lawyers to investigate independently the merits and demerits of a transaction. \(^28\) Contrast this with the DOJ method of investigation, which relies a great deal on the independent investigative techniques of DOJ attorneys and economists. While it is true that the DOJ also relies upon the submissions of the parties, the submissions here are typically raw data and not some canned final analysis. Thus, the analysis undertaken by the DOJ to determine whether there is a harm arising from the transaction is largely derived from the work of the DOJ staff. By comparison, any case by FERC describing anticompetitive circumstances arising from a merger is largely the outcome of an offer by the parties to divest (virtually or actually) certain assets as the result of a screen violation. In contrast, the DOJ’s stated policy is to not discuss remedy until an anticompetitive effect is found that requires remedy.

This is not to state that FERC lacks the capacity to engage in such an analysis. The Pacific/Enova case in particular proves that FERC is quite capable of engaging in independent sophisticated analysis. What it does lack, perhaps, is the ability to obtain sensitive competitive information. While the DOJ has civil investigative demand (CID) authority, FERC has little authority to initiate such subpoenas or at least a reluctance to use them. \(^29\) This inability/reluctance to fact-find makes it extremely difficult to engage in independent analysis, particularly with respect to competitive effects. What follows of course is increasing reliance upon parties for submission of information. Thus, the screen acts as a filter via which FERC can require information from the parties that it cannot obtain via independent means.

The trouble is that merger screens limit the analysis of the transaction from the world of relevant facts to the world of publicly available facts. The publicly available

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\(^28\) There are exceptions, of course. For example, in Wisvest-Connecticut, FERC (2001) redefined the relevant market, which the parties had expressed as NEPOOL, to a southwest Connecticut load pocket, causing the transaction to be problematic.

\(^29\) FERC has some degree of ability to engage in fact finding once it opens an investigation and schedules a merger application for a hearing, which it appears reluctant of late to do. During a proceeding before an ALJ, all parties to the proceeding, including FERC trial staff, may ask the ALJ to issue a subpoena. See also 16 U.S.C. Sect. 825f (discussing FERC’s authority to issue subpoenas to compel testimony and produce documents). See also 16 U.S.C. Sect. 825j (authority to conduct investigations related to electric energy). One possible difficulty is in FERC’s ability to obtain sensitive competitive information is limited relying upon protective orders that are sometimes viewed with skepticism.
facts tend to be the components of the screen. Intervening parties are likely to make the FERC aware of issues of transmission constraints and the like, but are not likely to be able to speak much on the issue of competitive effects. The issue of relevant product market may or may not be in the scope of public view depending upon the information available as to generation units and product bundling. Even if interveners are aware of some issues related to competitive effects, they are potentially unlikely to disclose that information if the basis of the argument is competitively sensitive information.

Thus, it could be argued that the basic motivation for a merger screen stems from imperfections in FERC’s ability to examine meaningfully mergers for anticompetitive effects. The problem with this argument is that the screen does little to remedy merger review inadequacies, while greatly increasing the problems stemming from such inadequacies. In contrast, The DOJ has been known to deal with antitrust review of electric utility mergers with a small number of lawyers, paralegals, and typically one economist assigned to each case. The tremendous efficiency of the endeavor is greatly due to its ability to gather information in a targeted fashion via both public and private sources.

The informational quandary also leads to a philosophical issue: FERC analysis of recent mergers begins with a submission by the parties that is pigeon-holed into Appendix A analysis. The only theory of harm typically addressed is a horizontal concentration issue. Should that theory not pan out, then there is little left for the Commission to do. And there is no reason that the theory would pan out, as the parties are likely to generate the analysis that could credibly pass the merger screen and, if that is impossible, propose remedies that allow the transaction to fly under the merger screen.

As discussed previously, slavish approach to the Guidelines alone is not sufficient for the detection of market power in electricity markets. The most likely difficulty that might arise in the acquisition of generation assets is the “fuel curve” problem. The fuel curve theory posits that the acquisition of marginal assets, in conjunction with ownership of inframarginal units, provides the incentive and ability to raise prices. While diversity of generation assets may increase efficiencies, it may also create market power. A straight-up counting of capacity may not detect market power arising from a fuel curve problem, and more analysis is necessary to determine the need to prevent and restrain such conduct Bush and Mayne (2004).

And, of course, vertical market power exercises do not lend themselves well to market power screens. Consider the DOJ’s consent decree in the matter of Pacific/Enova. Monopoly power over gas pipeline capacity, of course, could give rise to an increase in wholesale energy prices (in much the same fashion as the “fuel curve” theory described above), benefitting the pipeline’s affiliate-owned inframarginal generation units. However, it is not necessary for the pipeline to affect any supplier other than the marginal unit in order to bring about a price increase. Thus, the pipeline may or may not have market power in any sense except in the provision of gas to the marginal unit. Screens cannot be the end of the analysis here, either, and more investigation would be necessary to make any determination as to the effect that such market power might have on competition.

In sum, market share screens have the potential for “false negatives.” While corrections for any “false positives” brought about by market share calculations exist in the Guidelines in the form of entry and other analysis, there is no such corrective mechanism for “false negatives.” Thus, other methodologies must be employed to detect market power potential such as those described above. Contestable load analysis is not useful in this regard.

Thus, the usefulness of merger screens as a tool in analyzing electricity mergers is somewhat dubious. There is great potential to ignore buyer reaction factors, fail to account for a firm’s dominance in a market, and fail to consider the coordinated or unilateral effects at issue. Moreover, in many instances a market share analysis alone will not even detect market power, as in the cases of “fuel curve” or vertical theories of harm.

Finally, there are tremendous implications of merger screens in the debate over the concurrent jurisdiction of FERC and DOJ in the review of electric utility mergers. Calls for exclusive jurisdiction to be conferred upon the regulatory agency in light of the push for market power screens may in fact be cries for the elimination of any identification of nontraditional market power issues.

The tradeoff in terms of jurisdiction is akin to the tradeoff between market power screens and the hard work of electricity merger analysis. Screens offer predictable results, while merger analysis is sensitive to consumer behavior and other factors that may be less predictable. Similarly, FERC review of mergers is highly structured in Appendix A analysis, whereas DOJ review of mergers is contingent upon the theories of harm espoused by the DOJ and the evidence obtained from investigation. The outcomes of FERC merger review are public, leading to transparency of agency action and greater certainty. The outcome of a DOJ investigation is rarely public, but more likely public when there is some anticompetitive effect remedied by a consent decree or in rarer circumstances in a fix-it-first situation (USDOJ 1999).

It is difficult to call for an end to either regime because of the relative merits of each. However, conferring exclusive jurisdiction to FERC would create greater likelihoods of false negatives being generated in merger review because of the over-reliance upon merger screens. In the alternative, conferring exclusive jurisdiction to DOJ is likely to eliminate to a great degree false positives, but limits the degree of certainty for merging parties.

6 Conclusion

Market power detection is a crucial first step in preventing and restraining market power. A rational market participant would likely exercise market power if the benefits of engaging in the conduct exceed the expected costs. If FERC, using rudimentary screens, is unable to identify many instances of market power, then a generation company may benefit from its exercise without fear of detection and punishment. The costs to the consumers of unrestrained market power go beyond the higher costs imposed by the firm that is exercising market power and the costs of heightened administrative scrutiny. They include potentially the relocation of businesses and other ripple effects throughout the economy stemming from higher electricity prices.
However, the detection of market power is not for the faint-hearted. It requires rigorous analysis, large amounts of information, and serious thinking about the boundaries of the market (including consumer preferences, available supply, transmission constraints, the multitude of electricity products offered, etc.). It also requires an examination of entry, potential entry, potential exercises in conduct, and the like.

A market power screen, if properly applied, may determine in some instances the boundaries of the market and market shares within that market. However, it will not capture certain types of conduct, particularly if the screen is slavishly applied such that facts indicating that a different market analysis ought to be undertaken are ignored. And it is not necessarily the case that a single agency will get it right, even if it has all the information referenced above. In antitrust law, there is a tripartite of enforcement. Direct purchasers, competitors, state attorneys general, and the two federal enforcement agencies can bring antitrust actions. This heightens the probability of misconduct being detected.

In sum, screens are not the Holy Grail of market power detection. The beacon of market power screens is only Grail-shaped. The screens fail to heed the caution implicit in the Guidelines that markets are complex and that rigid application of the Guidelines may not lead to the right answer. The Guidelines’ caution rings particularly true in electricity markets, and FERC should be wary of using screens that will be unable to detect many instances of exercises of market power.

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Economic and Regulatory Trends Transforming the Interstate Natural Gas Pipeline Industry
Shale-Driven Natural Gas Abundance

How Real and What Are the Issues?

Energy Bar Association Midyear Meeting December 1, 2011

Richard G. Smead Director, Navigant Consulting, Inc.
How Has U.S. Gas Supply Been Performing for the Last Several Years?

Total U.S. Natural Gas Supplies, 2005 - 2010

Sources: U.S. Energy Information Administration, Shale production from Lippman Consulting Inc.
How About Shale Production by Itself?

Actual Shale Production, 1990 to 2011

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How Does it Compare with What Producers Expected Three Years Ago?

Producer 2008 Composite Forecast

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How Do Actuals Compare with EIA’s Latest Aggressive Forecast?

EIA’s 2011 Annual Energy Outlook

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What Does This Mean for Total Domestic Supply?

From the Mid-50s to 78 Bcf/d in 20 Years, and an Extra 10 Bcf/d by 2020

* AEO 2011 adjusted for 2009 compendium of various producer forecasts of major plays—more recent estimates are even higher.
What Has Gas Abundance Meant for Wellhead Prices?

Average Monthly US Wellhead Prices

$ per Mcf

$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00

Dec-2006
Mar-2007
Jun-2007
Sep-2007
Dec-2007
Mar-2008
Jun-2008
Sep-2008
Dec-2008
Mar-2009
Jun-2009
Sep-2009
Dec-2009
Mar-2010
Jun-2010
Sep-2010
Dec-2010
Mar-2011

July 2008 1_/ 

Source: U.S. Energy Information Administration

1_/ In the summer of 2008, a number of factors affected both the economy and the energy industry. However, it was in July 2008, prior to the massive economic meltdown that began with the Lehman bankruptcy in September, that two events first recognized natural gas abundance.—the Navigant Study and EIA’s measurement of production increase.
How Much Can We Have, How Long Can Abundance Last?

Proved Reserves Plus Assessed Resources

- The 2006 PGC Report’s Resource estimate was 1,530 Tcf, inclusive of about 137 Tcf of shale gas. EIA’s estimate was similar.
- In 2008, Navigant performed the North American Natural Gas Supply Assessment for the American Clean Skies Foundation, concentrating on the new shale contribution. The resulting total supply estimate was 2,247 Tcf, including 842 Tcf of shale gas.
- In June 2009, PGC issued its updated study—2,076 Tcf, including 616 Tcf of shale.
- In December 2010, EIA’s preliminary AEO is at 2,543, including 862 Tcf of shale.

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Gas Supply (Tcf)</th>
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<tbody>
<tr>
<td>PGC 2006</td>
<td>1,530</td>
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<tr>
<td>Navigant 2008 Study for ACSF</td>
<td>2,247</td>
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<tr>
<td>PGC 2008</td>
<td>2,076</td>
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<tr>
<td>EIA 2011 AEO</td>
<td>2,543</td>
</tr>
</tbody>
</table>

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Supply Abundance Should Be Here to Stay, but What Could Go Wrong?

- Various environmental concerns must be resolved.
  - Hydraulic Fracturing
  - Fugitive Methane
  - Methane Migration

- Whether or not the public questions are valid even when the facts disprove the claims of problems, the politics have become the reality—these issues must be resolved.

- The industry is committed to safe and responsible development, but there is obviously substantial political/regulatory pressure on the process in many regions.

- Deutch Committee Recommendations, NPC Study Efforts may help.

- Just about any scenario for resolution could add cost to wells, and could slow development—but not to the point of seriously diminishing supply growth.
  - Every technological advance increases production levels.
  - Even when producers turn to oil drilling, they are producing large amounts of associated gas.
  - In other words, even with more regulation, the gas will be there.

- So the United States and its consumers apparently do have a long-lived, clean-burning energy abundance of tremendous strategic importance.
U.S. Shale Gas Basins Align with the Nationwide Pipeline Grid – But What Happens to the Pipelines?

Sources: EIA, US Natural Gas Pipeline Network ©2011 Navigant Consulting, Inc.
Recent Trends in Infrastructure
A Federal Perspective

Energy Bar Association’s
Mid-Year Meeting, December 1, 2011

Berne L. Mosley, Deputy Director
OFFICE OF ENERGY PROJECTS
FEDERAL ENERGY REGULATORY COMMISSION
Why Shale Gas? Why Now?

- Project drivers
  - Market
  - Supply

- Impacts on Existing Infrastructure
Market Drivers

Natural gas is in demand...now more than ever!

- Firming-up Variable Power Generation (RPSs)
- New Baseload Power Generation
- Replacing / Converting Retiring Coal-Fired Plants
- Natural Gas Vehicles
Supply Drivers

- Shale gas is abundant and is becoming increasingly cheaper to produce.
- Rockies gas can now easily reach markets in the Northeast, and with Ruby, the Pacific Coast.
- Deeper shale formations (e.g., Utica) are now being considered as emerging supply sources.
Future U.S. Gas Supply

Source: EIA Annual Energy Outlook 2011 (April 2011) and EIA spreadsheets.
Shale Gas Plays in the United States

Lower 48 states shale plays

Source: EIA's Shale Gas Plays, Lower 48 States
<table>
<thead>
<tr>
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<th>Value 1</th>
<th>Value 2</th>
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<tr>
<td>Natural Gas Resources</td>
<td>1,739.2 Tcf</td>
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<td>Coalbed Gas Resources</td>
<td>1,897.8 Tcf</td>
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<td>Total U.S. Gas Resources</td>
<td>1,897.8 Tcf</td>
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<td>Future Gas Supply</td>
<td>2,170.3 Tcf</td>
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*Latest available value (dry gas), year-end 2009

Source: Based on data from ICF International and Compass Reports January and October 2011
Shale Gas Estimates

Source: Based on data from ICF International and Compass Reports January and October 2011
Summary of FERC Related Projects and Potential Projects Impacting the Shale Basins

<table>
<thead>
<tr>
<th>Natural Gas Basin</th>
<th>Capacity (MMcf/d)</th>
<th>Miles of Pipe</th>
<th>Compression (HP)</th>
<th>Cost (Millions)</th>
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<tr>
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<tr>
<td>Total Barnett, Woodford &amp; Fayetteville</td>
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<td>877</td>
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<td>Total Fayetteville</td>
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<td>Total Woodford</td>
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<td>50</td>
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<td>Total Haynesville</td>
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<td>196</td>
<td>229,716</td>
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<td>Total Marcellus</td>
<td>6,985</td>
<td>640</td>
<td>436,127</td>
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<td>Total Bakken</td>
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<td>Total Various Supplies</td>
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<td>Grand Total</td>
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<td>1,477,294</td>
<td>$13,836</td>
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Source: FERC

<table>
<thead>
<tr>
<th>Natural Gas Basin</th>
<th>Capacity (MMcf/d)</th>
<th>Miles of Pipe</th>
<th>Compression (HP)</th>
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<tr>
<td>Total Barnett</td>
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<tr>
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<tr>
<td>Total Haynesville</td>
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<td>5,228</td>
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<td>Grand Total</td>
<td>11,497</td>
<td>1,631</td>
<td>199,760</td>
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Source: FERC
The Marcellus Shale spans six states in the northeastern U.S.
Covers an area of 95,000 square miles at an average thickness of 50 ft to 200 ft
Estimated depth of production is between 4,000 ft and 8,500 ft
As of September 2008, there were a total of 518 wells permitted in Pennsylvania and 277 of the approved wells have been drilled
The average well spacing is 40 to 160 acres per well
The technically recoverable resources is estimated to be from 262 Tcf to 489 Tcf
The amount of gas in place is estimated to be from 1,500 Tcf to 2,445 Tcf

Source: Exhibit 19 and text - Marcellus Shale in the Appalachian Basin, DOE's Modern Shale Gas Development in the United States; A Primer, dated April 2009; and “Marcellus 2008: Report card on the breakout year for gas production in the Appalachian Basin” by Terry Engelder, Ph.D., Professor of Geosciences, PennState University
Marcellus Shale Projects

Approved or Pending Projects
- Appalachian Expansion (NiSource)
- Line 300 Exp (Tennessee)
- NiSource/MarkWest & NiSource
- N Bridge, TIME 3, TEMAX (TETCO)
- Appalachian Gateway (Dominion)
- Line N & N, R & I Projects (NFG)
- Tioga County Extension (Empire)
- NSD Project (Tennessee) & Ellisburg to Craigslist (Dominion)
- Northern Access (NFG & Tennessee)

Potential Projects
- Sunrise Project (Equitrans)
- TEAM 2012 Project (TETCO)
- Northeast Upgrade (Tennessee)
- Marc I (Central NY)
- West to East Connector (NFG)
- Appalachian Gateway (Dominion)
- Low Pressure East-West (Equitrans)
- East-West - Overbeck to Leidy (NFG)
- NJ-NY Project (TETCO & Algonquin)
- Appalachian to Market Expansion & TEAM 2013 (TETCO)
- MPP Project (Tennessee)

Source: FERC
# Summary of Natural Gas Facilities Impacting the Marcellus Shale Basin

<table>
<thead>
<tr>
<th>Natural Gas Basin</th>
<th>Status</th>
<th>Company/Project</th>
<th>Capacity (MMcf/d)</th>
<th>Miles of Pipe</th>
<th>Compression (HP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marcellus</td>
<td>In-Service</td>
<td>Texas Eastern Trans., LP (TEMAX &amp; TMCE II projects)</td>
<td>455</td>
<td>62</td>
<td>84,433</td>
</tr>
<tr>
<td></td>
<td>In-Service</td>
<td>Texas Eastern Trans., LP (Northern Bridge Project)</td>
<td>150</td>
<td>0</td>
<td>10,666</td>
</tr>
<tr>
<td></td>
<td>In-Service</td>
<td>Columbia Gas Trans., LLC (Appalachian Exp. Proj.)</td>
<td>100</td>
<td>0</td>
<td>9,470</td>
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<tr>
<td></td>
<td>In-Service</td>
<td>Tenn. Gas Pipeline Co. (Line 300 Expansion)</td>
<td>350</td>
<td>129</td>
<td>59,158</td>
</tr>
<tr>
<td>Marcellus</td>
<td>Prior-Notice In-Service</td>
<td>Columbia Gas Trans., LLC (Marcella Compressor/ MarkWest Upgrade)</td>
<td>250</td>
<td>4</td>
<td>0</td>
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<tr>
<td>Marcellus</td>
<td>Prior-Notice In-Service</td>
<td>Columbia Gas Trans., LLC</td>
<td>150</td>
<td>6</td>
<td>0</td>
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<tr>
<td>Marcellus</td>
<td>Under Construction</td>
<td>Equitran, LP (Low Pressure East and West Upgrade Project)</td>
<td>92</td>
<td>0</td>
<td>0</td>
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<tr>
<td></td>
<td>Under Construction</td>
<td>Dominion Trans., Inc. (Appalachian Gateway Project)</td>
<td>484</td>
<td>107</td>
<td>17,965</td>
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<tr>
<td>Marcellus</td>
<td>Approved</td>
<td>Central KY Oil and Gas Co. (MARC I Project)</td>
<td>550</td>
<td>39</td>
<td>31,660</td>
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<tr>
<td>Marcellus</td>
<td>In-Service</td>
<td>National Fuel Gas Supply Corporation (Line N R 81 Project)</td>
<td>150</td>
<td>20</td>
<td>4,740</td>
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<tr>
<td></td>
<td>Pre-Filing</td>
<td>Texas Eastern Trans. &amp; Algonquin Gas Trans. (NJ-NY Project)</td>
<td>800</td>
<td>20</td>
<td>0</td>
</tr>
<tr>
<td>Marcellus</td>
<td>Pending Under Construction</td>
<td>Equitran, LP (Sunrise Project)</td>
<td>314</td>
<td>47</td>
<td>14,205</td>
</tr>
<tr>
<td>Marcellus</td>
<td>Approved</td>
<td>Tenn. Gas Pipeline Co. (Northeast Upgrade Proj.)</td>
<td>200</td>
<td>16</td>
<td>20,720</td>
</tr>
<tr>
<td>Marcellus</td>
<td>Approved</td>
<td>Tenn. Gas Pipeline Co. (Northeast Supply Diversification Project)</td>
<td>636</td>
<td>40</td>
<td>22,310</td>
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<td>Marcellus</td>
<td>Approved</td>
<td>Dominion Trans., Inc. (Elkinsburg to Craig Project)</td>
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<td>0</td>
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<tr>
<td>Marcellus</td>
<td>Approved</td>
<td>Dominion Trans., Inc. (Northeast Expansion Project)</td>
<td>150</td>
<td>0</td>
<td>10,800</td>
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<tr>
<td>Marcellus</td>
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<td>Dominion Trans., Inc. (Northeast Supply Diversification Project)</td>
<td>200</td>
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<td>Marcellus</td>
<td>Pre-Filing</td>
<td>National Fuel Gas Supply Corporation (Northeast Access Project)</td>
<td>250</td>
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<td>36,000</td>
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<td>Marcellus</td>
<td>Approved</td>
<td>National Fuel Gas Supply Corporation (Station 230C Project)</td>
<td>320</td>
<td>0</td>
<td>14,210</td>
</tr>
<tr>
<td>Marcellus</td>
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<td>Tennessee Gas Pipeline Company (Station 230C Project)</td>
<td>0</td>
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<td>12,260</td>
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<tr>
<td>Marcellus</td>
<td>Pending</td>
<td>National Fuel Gas Supply Corporation (Line N 2012 Expansion Project)</td>
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<td>6</td>
<td>20,620</td>
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<tr>
<td>Marcellus</td>
<td>Pending (Prior Notice)</td>
<td>Equitran, LP (Blacksville Compression Project)</td>
<td>209</td>
<td>0</td>
<td>9,470</td>
</tr>
<tr>
<td>Marcellus</td>
<td>Construction Under</td>
<td>Empire Pipeline, Inc. (Tioga County Extension)</td>
<td>350</td>
<td>16</td>
<td>0</td>
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<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>6,985</strong></td>
<td><strong>640</strong></td>
<td><strong>436,127</strong></td>
</tr>
</tbody>
</table>

Source: FERC
Emerging shale gas plays and Rockies gas (via REX) have resulted in a change in the traditional flows on pipelines that historically have brought gas from the gulf to markets in the northeast.

The impact??

- a glut of gas in the Market Area
- underutilized pipeline facilities
- loss of traditional transportation revenue
Impacts on Existing Infrastructure

So…what’s a pipeline to do…

❖ File a rate proceeding?
❖ File to modify existing infrastructure?
❖ File to abandon certificated facilities?
❖ File to construct new facilities?
❖ All of the above?
Columbia Gulf Transmission Company – Docket No. RP11-1435-000

Tennessee Gas Transmission – Docket No. RP11-1566-000

Both seek to make their recourse rates less “distance sensitive”…Columbia Gulf is proposing a postage stamp rate, while Tennessee proposes to shift costs from mileage to non-mileage.
From Testimony Filed in the Proceeding:

- The flattened basis differential between the price of gas near the Gulf of Mexico and the price of gas in the Midwest and Northeast due to the increase in new gas supplies means there is less economic incentive to transport Gulf of Mexico gas to northern points.

- CGT’s customers are now increasingly sourcing gas from the shale production areas to the west of CGT’s system. This means that CGT’s customers are now using receipt points near Delhi, Louisiana instead of traditional points on CGT’s Onshore and Offshore laterals resulting in decreased throughput on the Onshore zone.

- In general, the new pipelines that provide takeaway capacity from the Texas, Oklahoma, Louisiana, and Arkansas shale plays have helped integrate the pipeline system in the Eastern U.S. These pipelines allow significant volumes to flow west-to-east, which has decreased the differential that once existed between the price of gas in Texas and Louisiana and the price of gas in eastern markets. The market is therefore no longer as reliant on CGT to bring supplies to the market. As a result, demand for transportation capacity on CGT’s system has decreased as the pipeline system has grown more integrated. The declining production costs associated with developing shale gas supplies along with the increased production from the Marcellus Shale will likely cause a further flattening of the price differential between Gulf of Mexico supply and northern markets.
From Testimony Filed in the Proceeding:

- CGT may lose some of its northern LDC customers who can access the Marcellus Shale or gas supplies from the Rockies without using CGT’s system.

- Tennessee is now receiving approximately 30% of its supply from the middle of its system (Zone 4), up from 5% in 2009. (TPG-132, page 20, lines 1-3).

- In the past, supply shortages often resulted from damage to offshore facilities due to hurricanes. Today, such shortages would not have the same operational impact because Tennessee has more supply being delivered directly into its market are from REX and Marcellus. (TGP-132, page 29, lines 5-10).

- Natural gas from REX and Marcellus has displaced receipts from traditional sources in south Texas and the Gulf of Mexico. For example, physical receipts of Marcellus gas into Tennessee’s 300 Line located in Pennsylvania have increased from zero in 2008 to nearly 1 Bcf/d by November 2010. (TGP-141, page 10 line 17 – page 11, line 2).

- In recognition of the increased Marcellus shale gas and other supplies entering into the Tennessee system in Zone 4, Tennessee proposes to modify the location of existing pooling points. By moving the pools there will be a reduced likelihood of a restriction into the pool due to constrained segments of pipe. (TGP-141, page 46, line 13 – page 47, line 18).
The following pipeline companies have sought FERC approval to make facility changes to existing infrastructure, and amend Presidential Permits to allow transportation and exportation of shale gas into Canada:

- Empire
- Iroquois
- Maritimes and Northeast
- National Fuel
- Tennessee
- Vector
Existing Pipelines are Eyeing Backhauls in Response to Marcellus Growth

Existing pipelines are mulling the option to backhaul gas as the rapid growth of shale gas production redraws the map for pipeline flows across North America:

- The growing market chatter regarding offering backhaul capacity on Rockies Express Pipeline has been increasing, with the pipeline company even mentioning it as an area of growth for next year in an investor presentation in January 2010.

- Tennessee Gas Pipeline announced recently that it has contracted for some 400,000 Mcf/d of backhaul capacity from the Marcellus Shale to Southeastern markets this year and projects to have about 936,000 Mcf/d in 2012.

- Transcontinental Gas Pipe Line officials announced that the pipe has the ability to move gas west to Leidy, Pennsylvania, and even back down to Transco zone 5 in the Mid-Atlantic.
Abandoning Existing Infrastructure

The following pipelines have sought FERC authority to abandon certificated facilities, typically in historic production areas (including offshore) and on parts of their systems with low throughput:

- ANR
- Columbia Gulf
- Florida Gas Transmission
- Northern Natural
- Southern Star
- Tennessee
- Texas Eastern
- Transco
The following pipelines have sought to construct new facilities to transport Marcellus shale gas:

- Equitrans
- National Fuel
- Tennessee
- Texas Eastern
- Transco
- Dominion
- Central NY Oil and Gas
Moving the “Heavies” to Market:

- Several traditional “Long Haul” pipelines are exploring ways to take Ethane and other liquids to the gulf coast region from Marcellus.
- This would involve reversal of flow on segments of existing pipeline facilities.
- Could be accomplished by modifying existing compression to handle pumping liquids, and possibly uprating operating pressures to handle liquids.
- Would require abandonment authority from FERC.
Increases in flows from the Gulf Coast to the east are due to increases in Mid-continent shale gas production.

Modest increases in the Rockies both east and west.

Marcellus gas production growth displaces gas flows into the Northeast U.S. (Shocks within the Northeast are not depicted on this interregional flow map).

Declining conventional production in Alberta and increasing gas consumption for oil sands development cause flows from Western Canada to decline.

Source: ICF International
Substantial increases in flows continue to occur out of the Mid-continent shales and the Rocky Mountain producing basins.

Marcellus gas production growth continues to displace gas flows into the Northeast U.S. [shifts within the northeast are not depicted on this interregional flow map].

Flows out of western Canada will continue to remain low due to the weak supply/demand balance in western Canada.

Source: ICF International
I. Shale Gas Development Is Most Significant Recent Trend Impacting FERC Regulatory Environment, Resulting In:

- Newly constructed pipelines and laterals in shale development areas.
- Dislocations of traditional gas flows, especially from offshore, and changing flow dynamics.
- Spate of rate case, facility sales, and abandonment filings because of declining throughput offshore.
- Applications to make LNG terminals bidirectional, in order to liquefy domestic natural gas for LNG export.

II. A Major Regulatory Impact For Producers Has Been On Offshore Facilities.

A. Different commercial models for addressing throughput declines on the offshore.

1. Abandonment Filings (full and partial):

- Northern Natural Gas Company attempted to abandon and terminate service on its entire MOPS facilities. FERC rejected application, Northern Natural Gas Co., 135 FERC ¶ 61,048, reh’g denied, 137 FERC ¶ 61,091 (2011).


- Abandonment requests by more than one single interest in jointly owned facilities, e.g., Texas Eastern Transmission LP and Columbia Gulf Transmission Company, with question of who, if any, will be remaining and obligated to provide service, CP11-103 (filed 2/23/2011) and CP11-13 (filed 10/21/2010).

- Tennessee Gas Pipeline Company filed to sell offshore assets to Kinetica, CP11-44, RP11-1597 (filed 12/3/10), to be refunctionalized as gathering, or in the alternative, to be operated under limited jurisdiction certificate. FERC denied the application in a recent order issued on November 3, 2011. Tennessee Gas Pipeline Co., 137 FERC ¶ 61,105 (11/3/2011).

2. Rate case filings.

- Enbridge Offshore Pipelines (UTOS) LLC filed to increase its rates from $.017 cents to $2.048 cents/dth, but negotiated a gradual phase-out and abandonment. FERC approved settlement, Enbridge Offshore Pipelines (UTOS) LLC, 135 FERC ¶ 61,096 (2011).

- Stingray Pipeline Company L.L.C., filed to increase rates from 15 cents to 84 cents/dth. Settlement negotiations failed and case set for hearing, RP11-1957 (filed 3/31/11).

- Numerous limited Section 4 hurricane surcharge filings to recover hurricane related costs.

3. Proposed offshore facility sales.

- ANR Pipeline Company selling its offshore facilities to wholly owned affiliate (TC Offshore LLC) to operate offshore facilities as an interstate pipeline, CP11-543 (filed 9/1/11).

- Southern Natural Gas Company selling its offshore facilities to an unaffiliated third party (High Point Gas Transmission, LLC) to be operated as an interstate pipeline, CP12-4 (filed 10/7/11).
- Trunkline Gas Company, LLC selling its offshore facilities to existing affiliated offshore pipeline, Sea Robin Pipeline Company, LLC, to be owned and operated by Sea Robin, CP12-5 (filed 10/7/11).

B. Impact has been, and will be, to increase cost of offshore transportation.

1. Higher transport rates would be paid for receiving the same service.

2. Higher transport rates for offshore facilities that would be paid in addition to onshore rates paid to existing pipelines results in rate stacking.

3. As offshore transport rates increase in a low-cost environment, offshore drilling is economically less attractive. With higher transport rates there will be less drilling, and with less drilling there will be even higher transport rates.

4. Higher transport rates result in competitive disadvantage to offshore supplies vis a vis onshore supplies.

5. Higher transport rates could result in premature abandonment before gas supplies are depleted from existing wells.

C. What’s an offshore producer to do?

1. Public interest is disserved if producers are forced to premature abandonment due to higher transport rates.

2. Public interest is disserved if consumers have fewer available natural gas supplies and the delivered cost of natural gas increases.

3. Public interest is disserved if pipelines forced out of business because of escalating costs and decreasing throughput. Producers need pipelines and pipelines need producers.

D. Necessary FERC Policies To Address The Problem.

1. FERC needs to address the problem of cost responsibility and provide rate certainty in this new regulatory environment. Rate certainty is crucial for producers to make long-term drilling decisions, especially on the offshore and in a low-price environment.
2. The tools in Sections 4, 5, and 7 of NGA are just as relevant today as they were in 1938.

3. Section 7, properly implemented, prevents premature abandonment where there is flowing gas, as in MOPS case, and prevents abandonment to a non-jurisdictional status resulting in increased rates, as in the Tennessee case.

4. Sections 4 and 5, properly implemented, provide for just and reasonable rates.

5. Goal, as always, is to achieve a fair balance among competing interests.

6. Some guiding regulatory principles are as follows:

- Abandonment from service should not be permitted so long as there is flowing gas in sufficient quantities for a reasonably projected period of time. Offshore producers are typically captive to the one pipeline to which they are connected.

- FERC should not approve applications to refunctionalize offshore interstate pipelines to unregulated gathering.

- FERC should continue to be open to limited jurisdiction certificates where pipeline owners are shipping solely their own natural gas supplies.

- FERC should consider rate increase impacts on existing shippers in evaluating abandonment applications, as it did in recent Tennessee case, and scrutinize, and adjust where appropriate, newly proposed rates in order to determine whether the sale is in the public interest.

- Settlement is the preferred process, as in the phase-out of UTOS, but each case will be different, depending on alternatives. Pipelines should attempt to settle with impacted producers prior to filing at FERC, and if not, FERC should set cases for settlement judge procedures prior to hearing. Notably, in Tennessee and Southern, there were efforts to settle with mainline customers but not the producer shippers who are directly impacted.

- From a commercial perspective, there needs to be a “rationalizing” of offshore load, based on reserve life, geographical locations, and pipeline load
factors. This requires pipelines and producers to work together to construct solutions that meet their mutual commercial and operational needs.

- From a regulated rate perspective, FERC should reaffirm its policy requiring cost sharing between the shippers and the pipeline for costs related to unsubscribed capacity. It is not in the public interest to award the pipelines rates based on actual billing determinants adjusted for discounts along with a healthy ROE, essentially keeping the pipeline whole on all costs with a profit, when the result is ever escalating transportation rates creating a “death spiral” and causing economic shut-in of offshore production.

- FERC should not permit limited Section 4 filings to track one rate design element, such as throughput decline, or hurricane costs. This immunizes the pipeline from scrutiny regarding other rate component areas where costs have been reduced. All attempts at piecemeal litigation should be rejected, as the FERC recently did in its MOPS rehearing order.

- Distance or zoned-based rates could help or exacerbate the problems, depending upon the facts, by stranding certain portions of the pipeline system and shifting costs among shippers. Any proposals to shift costs should be fully scrutinized and transition mechanisms should be considered to avoid rate shock.

- FERC should continue its vigilance in undertaking Section 5 show cause orders in order to protect both offshore and onshore shippers, especially if offshore abandonments are approved, where pipelines have no Section 4 rate case filing obligations.

- Finally, FERC should revamp its Section 311 pipeline regulations for onshore pipelines built to transport the shale gas, to require all open access provisions currently applicable only to interstate pipelines, including requiring Section 311 pipelines to sell firm transport and allow capacity release. (Pending Notice of Inquiry, Capacity Transfers on Intrastate Natural Gas Pipelines, 133 FERC ¶ 61,065 (2010)).
NOTES
Ethics Panel
A Review of The Model Rules of Professional Conduct, Statutes and Regulations as They Apply to FERC Practitioners

Sidney Rocke
Deputy Associate General Counsel
Marcos A. Araus
Staff Attorney
Model Rule 4.1 Truthfulness in Statements to Others

In the course of representing a client a lawyer shall not knowingly:

(a) make a false statement of material fact or law to a third person; or (b) fail to disclose a material fact to a third person when disclosure is necessary to avoid assisting a criminal or fraudulent act by a client, unless disclosure is prohibited by Rule 1.6 (confidential lawyer-client information).
Truthfulness in Statements and Disclosures to the Commission (Model Rule 4.1 and 18 USC 1001)

Model Rule 4.1- Applied

Expert witness’s lie about credentials during deposition was material because it formed the basis for expert opinion relied on to negotiate settlement. Perjured testimony was so material as to corrupt opinion triggering reporting requirement to tribunal as fraud. See VA LEO 1650.
Model Rule 4.1- Applied

- Lawyer's decision to submit client's incorrect financial data to opposing party without attempting to verify validity, in view of lawyer's own suspicions about it, sufficiently evinced reckless disregard constituting dishonest conduct. See *In re Silverman*, 549 A.2d 1225, 1238 (N.J. 1988).
Model Rule 4.1 - Applied

Client’s lie during a deposition, even though not considered relevant to the case’s merits, constituted a fraud upon the tribunal and the attorney must reveal the client’s knowingly false statement to the tribunal if the client is unwilling to do so. See VA LEO 1451.
Truthfulness in Statements and Disclosures to the Commission (Model Rule 4.1 and 18 USC 1001)

18 USC 1001 criminalizes willful making of a materially false statement in any matter within the jurisdiction of the United States.

Applies to Executive, Legislative and Judicial Branches.

Goal: stop deceptive practices that frustrate or impede Government action.
Truthfulness in Statements and Disclosures to the Commission (Model Rule 4.1 and 18 USC 1001)

- Can be oral or written
- Sworn or unsworn
- Voluntary or required by law

18 USC 1001 Form and context
Truthfulness in Statements and Disclosures to the Commission (Model Rule 4.1 and 18 USC 1001)

- 18 USC 1001 Elements Government must prove
  1. Was act or statement within the jurisdiction of the agency?
  - Agency’s jurisdiction to be interpreted broadly. See United States v. White, 270 F.3d 356 (6th Cir. 2001).

- Facts: Defendant submitted reports containing false water measurement information to Kentucky water division. Convicted of making false statements under 18 USC 1001. Defendant argued that the alleged false statements pertained to a matter before a state agency, outside the jurisdiction of the EPA.

- Issue: Whether reports filed with state agency were within EPA jurisdiction under 18 USC 1001.

- Holding: Because defendant influenced the course of an investigation, which could result in EPA enforcement action, statements made in reports were materially false. EPA could exercise its enforcement authority with noncompliant local water systems in Kentucky.
Truthfulness in Statements and Disclosures to the Commission (Model Rule 4.1 and 18 USC 1001)

- 18 USC 1001 Elements Government must prove
  2. Was act or statement material?
  - Sufficient that the statement have the capacity or a natural tendency to influence the determination required to be made. See Kungys v. United States, 485 U.S. 759, 770 (1988).
  - “The issue to which the false statement is material need not be the main issue; it may be a collateral issue. And it need not bear directly upon the issue but may merely augment or diminish the evidence upon some point. But it must have some weight in the process of reaching a decision.” United States v. Weinstock, 231 F.2d 699, 703 (D.C. Cir. 1956).
Truthfulness in Statements and Disclosures to the Commission (Model Rule 4.1 and 18 USC 1001)

18 USC 1001 Elements Government must prove
3. Was it done knowing it was false?
   - Intent to deceive
   - Literal truth not appropriate for prosecution
   - Look for material omission or concealment
   - Conscious avoidance of learning facts may substitute for actual knowledge. See United States v. Schaffer, 600 F.2d 1120, 1122 (5th Cir. 1979).
Truthfulness in Statements and Disclosures to the Commission (Model Rule 4.1 and 18 USC 1001)

- False statement under 18 USC 1001 can be contained in any records subject to Government inspection
  - Gonzales v. United States, 286 F.2d 118 (10th Cir. 1960), rev’d on other grounds.

Facts: President of a rural electric cooperative, was convicted under 18 USC 1001 after he submitted false statements in monthly reports regarding the cooperative's financial status to the Rural Electrification Administration (REA), a federal lending agency that was financing the construction of its facilities.

Issue: Whether submittal of false statement in monthly report submitted to REA is considered a false statement under 18 USC 1001.

Holding: The court found that the statements made were within the agency's jurisdiction because the agency had a right to be informed of the financial status of those corporations to which it made loans.
Truthfulness in Statements and Disclosures to the Commission (Model Rule 4.1 and 18 USC 1001)

- What Government does **not** have to prove
  - Financial loss to Government
  - False statement does not have to be submitted directly to Government – OK through middleman
Truthfulness in Statements and Disclosures to the Commission (Model Rule 4.1 and 18 USC 1001)

- What Government does **not** have to prove
  - No favorable action based on statement is required
  - No reliance on statement need be shown by the Government
Communications With Other Parties and The FERC (Model Rule 4.2 and 18 CFR 385.2201)

- **Model Rule 4.2 – Communication with Person Represented by Counsel**
  - In representing a client, a lawyer shall not communicate about the subject of the representation with a person the lawyer knows to be represented by another lawyer in the matter, unless the lawyer has the consent of the other lawyer or is authorized to do so by law or a court order.
Communications With Other Parties and The FERC (Model Rule 4.2 and 18 CFR 385.2201)

- **Model Rule 4.2 – Communication with Organization Represented by Counsel**

  It is inappropriate to communicate with a constituent of an organization that is represented by counsel that supervises, directs or regularly consults with the organization’s lawyer concerning a matter that may be imputed to the organization for purposes of criminal or civil liability.
Communications With Other Parties and The FERC (Model Rule 4.2 and 18 CFR 385.2201)

- Model Rule 4.2 – Communication with Person Represented by Counsel
  - It is appropriate to communicate with a represented person, or an employee or agent of such a person, concerning matters outside the representation.
Communications With Other Parties and The FERC (Model Rule 4.2 and 18 CFR 385.2201)

- 18 CFR 385.2201 Rules Governing off-the-record communications
  - In any contested on-the-record proceeding, no person outside the Commission shall make or knowingly cause to be made to any decisional employee, and no decisional employee shall make or knowingly cause to be made to any person outside the Commission, any off-the-record communication.
18 CFR 385.2201 what constitutes a “contested on-the-record proceeding”?

- Any proceeding before the Commission to which there is a right to intervene and in which an intervenor disputes any material issue.
- Any proceeding initiated by filing of a complaint with the Commission.
- Any proceeding initiated by the Commission on its own motion or in response to a filing, or any proceeding arising from an investigation under part 18 CFR 1b beginning from the time the Commission initiates a proceeding.
Communications With Other Parties and The FERC (Model Rule 4.2 and 18 CFR 385.2201)

- 18 CFR 385.2201(c) what **DOES NOT** constitute a “contested on-the-record proceeding”?
  - Notice and comment rulemakings 5 USC 553
  - Investigations under 18 CFR 1b
  - Proceedings not having a party or parties, or
  - Proceedings in which no party disputes any material issue
Communications With Other Parties and The FERC (Model Rule 4.2 and 18 CFR 385.2201)

- 18 CFR 385.2201(c) - Procedural Exception
  - Procedural inquiries, such as a request for information relating solely to the status of a proceeding, generally, are not considered relevant to the merits and therefore not prohibited by the ex-parte rule. See Louisiana Ass’n. of Indep. Producers v. FERC, 958 F. 2d 1101, 1112-13 (D.C. Cir. 1992).
Conflicts of Interest for former and current Government employees (Model Rule 1.11 and 18 USC 207)

- Model Rule 1.11
  Special Conflicts Of Interest For Former And Current Government Officers And Employees –
  - Restrictions on matters in which a lawyer participated personally and substantially
  - “Matters” interpreted broadly
Conflicts of Interest for former and current Government employees (Model Rule 1.11 and 18 USC 207)

- Model Rule 1.11 – as applied to *former* public officer or government employee
  - Subject to Rule 1.9(c) (duties to former clients)
  - Shall not otherwise represent a client in connection with a matter in which the lawyer participated personally and substantially as a public officer or employee, unless the appropriate government agency gives its informed consent, confirmed in writing, to the representation.
Conflicts of Interest for former and current Government employees (Model Rule 1.11 and 18 USC 207)

- Model Rule 1.11 – Application of the rule for former public officers or government employees
  - A former government attorney who worked on an initial draft rule can work on final version of the rule that differs substantially from the initial draft.
  - Where rule that ultimately is promulgated is based on a later draft for which the attorney did not have substantial responsibility and which differed substantially from the initial draft for which the attorney had substantial responsibility, it would not be improper for an attorney to accept private employment by parties challenging the rule. See VA LEO 1299.
Conflicts of Interest for former and current Government employees (Model Rule 1.11 and 18 USC 207)

- Model Rule 1.11 – as applied to *current* public officer or government employee
  - Subject to Model Rule 1.7 (conflict of interest) and 1.9 (duties to former clients)
  - Shall not participate in a matter in which the lawyer participated personally and substantially while in private practice or nongovernmental employment, unless the appropriate government agency gives its informed consent, confirmed in writing, to the representation.
Conflicts of Interest for former and current Government employees (Model Rule 1.11 and 18 USC 207)

- **Model Rule 1.11 - Application of the rule for current government employees**
  - An attorney who worked on anti-trust class action at a large law firm and subsequently employed by government agency can work on anti-trust laws impacting attorney’s former client.
    - Any anti-trust enforcement matter which did not involve the same relevant facts, same parties or same subject matter would not be “substantially related” to prior representation. See VA LEO 1613.
Conflict of Interest for former and current Government employees (Model Rule 1.11 and 18 USC 207)

- **18 USC 207**
  - Criminal statute that restricts certain activities of former Government officers and employees of the executive and legislative branches
  - Goal is to prevent employee from “switching sides”
Conflict of Interest for former and current Government employees (Model Rule 1.11 and 18 USC 207)

- 18 USC 207(a)(1) - Permanent ban on particular matters involving specific parties in which employee participated personally and substantially.
- For ban to apply, all elements must be met:
  - (a) representing another person, (b) through communication or appearance, (c) before a federal department, agency or court, (d) with the intent to influence the federal entity, (e) in connection with: (1) any particular matter involving a specific party or parties; (2) in which you participated personally and substantially as a government employee; and (3) in which the United States is a party or has a direct and substantial interest.
Conflict of Interest for former and current Government employees (Model Rule 1.11 and 18 USC 207)

18 USC 207(a)(2) - Two-year ban applies to senior officials

- Applies to all particular matters involving a specific party or parties that were under consideration by subordinates during supervisor’s last year of service, even if the senior official was not personally and substantially involved.
Conflict of Interest for former and current Government employees (Model Rule 1.11 and 18 USC 207)

- 18 USC 207(c) - One year cooling off period for senior officials
  - Applies to senior officials and prohibits contacting their former agencies for one year from termination of government service regarding any business matter.
Conflict of Interest for former and current Government employees (Model Rule 1.11 and 18 USC 207)

- 18 CFR 385.2103(a) - Ban on participation in certain matters before the Commission
  - Former employees are prohibited from post-employment participation in matters at the Commission, including rulemakings, in which the employee was personally and substantially involved while at the Commission.
A Review of the Model Rules of Professional Conduct, Statutes and Regulations as they apply to FERC Practitioners

Selected Legal Authority


- United State v. White, 270 F.3d 356 (6th Cir. 2001).

- VA LEO 1650
- VA LEO 1477
- VA LEO 1451
- VA LEO 1613
- VA LEO 1493
- VA LEO 1299
- Model Rule 1.6
- Model Rule 1.7
- Model Rule 1.9
IN THE MATTER OF MELVIN SILVERMAN, AN ATTORNEY AT LAW

No. D-SS

Supreme Court of New Jersey

113 N.J. 193; 549 A.2d 1225; 1988 N.J. LEXIS 111

March 1, 1988, Argued
October 28, 1988, Decided


PRIOR HISTORY: [***1] On an order to show cause why respondent should not be disbarred or otherwise disciplined.

COUNSEL: William R. Wood, Deputy Ethics Counsel, argued the cause on behalf of Office of Attorney Ethics.

Roger A. Lowenstein argued the cause for respondent (Dickson, Creighton & Lowenstein, attorneys).

JUDGES: For Suspension -- Chief Justice Wilentz and Justices Clifford, Handler, Pollock, O'Hern, Garibaldi and Stein join. Opposed -- None.

OPINION BY: PER CURIAM

OPINION

[***2] The unethical conduct at issue in this disciplinary proceeding arises out of respondent's participation in a business venture [*196] with a former client and his testimony in the civil proceedings that resulted from it. The record before the Disciplinary Review Board (Board) consisted of a Presentment filed by the District IIB Ethics Committee (Committee), a detailed stipulation of facts entered into by respondent and the Office of Attorney Ethics (OAE), the proceedings and decision of the Client's Security Fund, and the record of the aforementioned civil trial. The Board concluded respondent [***1227] had entered into an employment relationship with a client in violation of DR 5-101(A), conducted a business transaction with a client [***2] in violation of DR 5-104(A), committed numerous misrepresentations in the course of that transaction in violation of DR 1-102(A)(4), and had made several false statements under oath. Despite respondent's otherwise unblemished record both prior to and since the relevant events in this case, the Board recommended disbarment.

Our careful and independent review of the record leads us to accept in part and reject in part the Board's findings and recommendation. The Board's findings regarding respondent's misrepresentations and participation in a business transaction with a client are amply supported by the record, and indeed by multiple concessions found in the stipulation and respondent's brief. Further, we are in partial agreement with the Board's conclusions concerning the accuracy of respondent's sworn testimony. We cannot agree, however, that clear and convincing evidence establishes an attorney-client relationship concerning the relevant transaction, nor can we conclude that disbarment is warranted. Due to several mitigating factors, our judgment is that respondent's six-year suspension constitutes a discipline sufficient to protect the public.

I

Respondent was admitted [***3] to the bar of this
State in 1970, and to the bar of the United States Patent and Trademark Office [*197] two years later. His practice has consisted almost exclusively of matters in the patent field and has provided him with a modest income. Events relevant to this case began in late 1978 and were detailed by the Board as follows:

"On November 15, 1978, respondent entered into an agreement to purchase a large, prestigious patent agency known as Haseltine, Lake and Waters (HLW) from Eric Waters (Waters) for $750,000. Pursuant to the terms of the agreement, respondent was to pay Waters the sum of $350,000 at closing set for January 12, 1979; $130,000 on January 12, 1980; and additional, unspecified amounts over a number of years pursuant to a formula based upon past and future earnings of HLW.

"Respondent, a patent attorney with offices in Clifton, did not have the personal funds or assets necessary to obtain sufficient credit for the purchase of HLW. Consequently, it was respondent's intention to use HLW's accounts receivable and good will as collateral. However, attempts to borrow funds from commercial lenders proved unsuccessful.

"In January 1979 respondent had occasion [*199] to meet with Fred Ferber (Ferber), a client for whom respondent's law firm had performed patent work from 1973 through 1977. Although Ferber initiated the meeting to discuss a possible new patent, respondent soon told him about difficulties he was encountering in obtaining financing for the acquisition of HLW. At the time of this discussion Ferber, a famous inventor recognized as the father of the modern ball point pen, owned a substantial amount of real estate in New Jersey but was virtually cash poor and under tremendous financial pressure. He was 75 years old, his wife was seriously ill with cancer and he was in default on numerous debts including mortgages, real estate taxes and unpaid legal fees due and owing to respondent's law firm. Seeing the HLW transaction as an opportunity for him to alleviate his financial problems, Ferber agreed to allow respondent to use a 212 acre tract of his property as collateral for a $400,000 loan in exchange for money with which to pay his debts and meet living expenses.

"Armed with Ferber's pledge of collateral, in early February 1979 respondent prepared a prospectus to be used in support of his application for the $400,000 loan. This [*200] prospectus contained information concerning Ferber's and respondent's respective financial conditions. However, portions of the prospectus as well as the loan application contained information respondent knew to be false. Respondent admitted that the application contained exaggerations of Ferber's worth. Even though Ferber was dictating information, I [*201] realized there were exaggerations and there were * liabilities understated * * *.'

"Among the misrepresentations found in respondent's financial statement was an entry that his interest in the law firm of Silverman and Jackson was worth $165,000. However, the law firm had dissolved six months earlier in August 1978 and had no value. An additional entry placed a value of $20,500 on Technology Assistance Corporation, a company formed by respondent. However, the company had not been incorporated, owned no assets, had never [*198] conducted any business and had no monetary value. Values of other assets were similarly misrepresented.

"The Ferber financial statement contained more serious misrepresentations. One entry listed the value of Ferber's patent rights in a process known as 'Protosoil' as $200,000, a figure respondent [*202] knew to be speculative. An additional entry indicated that Ferber had $65,000 cash on hand when
respondent knew Ferber was cash poor. The financial statement also indicated that Ferber owned an art collection worth $40,000 and miscellaneous securities worth $60,000 when respondent knew that these entries were improbable at best. Moreover, the financial statement failed to list all of Ferber's liabilities, including accrued interest, at true value.

"On March 26, 1979, after the prospectus and financial statements had been presented by an intermediary, respondent formally submitted the loan application to Liberty Federal Savings & Loan Association (Liberty). The application referred the bank to a report on Ferber's income prepared by Ira S. Herman, C.P.A. (Herman), respondent's first cousin. In this report Herman indicated that Ferber's income during the six year period from 1973 through and including 1978 was $413,477 per year. This figure was based upon Ferber's sale of certain real estate to the State of New Jersey in 1973 for $2,800,000. In reality, however, Ferber had no source of income during the years in question and his net profit on the sale of the property, after the satisfaction of mortgages and liens, was less than $150,000. Respondent was fully aware of this misrepresentation at the time the report was prepared and submitted.

"The loan application contained several other misrepresentations of which respondent was aware. In one section, the application indicated that Ferber was not then a party to a law suit and that no properties owned by him were the subjects of foreclosure actions. However, at the time the application was filed respondent, on behalf of Ferber, was attempting to negotiate the settlement of a foreclosure action that had been filed against Ferber. The application further indicated that Ferber held $260,000 in stocks and bonds and had a net worth of $1,944,000 when respondent knew that both figures were exaggerated and constituted material misrepresentations.

"At the time respondent submitted the loan application, the New Jersey Usury Law limited interest on personal loans to a rate of 9 1/2%. Since Liberty was issuing loans at a rate of 14%, respondent was advised that the loan could only be made to a corporation. Upon receiving this information, respondent conferred with Ferber and suggested that Ferber and his wife, Hedwig, convey title to the 212 acre tract into a corporate 'shell' known as Eastern Star Enterprises, Inc. (Eastern) which respondent had previously formed for other purposes.

"On or about April 10, 1979, respondent secured the Ferbers' consent to the proposed conveyance and prepared three corporate resolutions to facilitate the transaction. The first resolution named Fred, Hedwig and respondent as directors of Eastern. The second resolution appointed Fred as president, Hedwig as vice president and respondent as secretary. This resolution further provided for distribution of 500 shares each of authorized but unissued stock to Fred and Hedwig. The third resolution contained four provisions authorizing the board of directors to apply for a loan of between $400,000 to $435,000; the corporation to accept title to the 212 acre property from the Ferbers; respondent to execute any and all documents necessary to effectuate the loan; and respondent to execute a note of not more than $85,000 to Waters to be secured by a mortgage against the 212 acre parcel.

"The deed conveying the 212 acre property from the Ferbers to Eastern was prepared by respondent and acknowledged by him on April 11, 1979. The Ferbers' signatures were purportedly witnessed by respondent's law partner. However, during the course of a civil trial concerning respondent's acquisition of
HLW, the partner testified that he had not witnessed the deed and that the signature thereon was not his.

"From the time of their initial meeting in January 1979 through the preparation of the three corporate resolutions and execution of the deed, the Ferbers were without benefit of independent counsel and respondent failed to advise them that it was in their best interests to retain an attorney. It was not until after the corporate resolutions and deed had been signed that respondent advised the Ferbers to contact an attorney. In the interim, respondent, who has steadfastly denied representing the Ferbers in his capacity as an attorney, helped the Ferbers obtain additional mortgage monies with which to meet their everyday living expenses. Respondent's 'assistance' included negotiations to settle or forestall foreclosure actions involving various Ferber properties.

"On April 17, 1979, after finally being advised by respondent to secure his own attorney, Fred Ferber contacted William S. Robertson, [***10] Esq. (Robertson), an attorney from Wayne, New Jersey, who had represented Ferber in the past. On the following day, April 18, 1979, Robertson called respondent, advised him that he was representing the Ferbers and requested copies of any and all documents relating to the HLW acquisition. Respondent initially complied with Robertson's request by sending him a copy of the prospectus. Upon reviewing the document, Robertson pointed out were -- did not relate to any asset that the bank was relying upon, okay, although Ferber in -- had valued and I had listed the property at a higher value the bank had done their own appraisal and come up with a value which, to them, was satisfactory. But this is how I rationalized it, wrong though it was.'

"On April [***11] 23, 1979, Liberty issued a letter of commitment to Eastern approving a first lien mortgage loan on the 212 acre property in the amount of $400,000 at an interest rate of 14% to be repaid in monthly installments based upon a 15 year pay-out but due in full in ten years. The commitment letter also set forth a number of conditions precedent including, but not limited to, the Ferbers' personal guarantees, cash collateral in the amount of $100,000 to be pledged by HLW or Waters, the Ferbers' tax returns for the preceding three years, and the Ferbers' certified financial statements.

[*200] "On April 25, 1979, respondent met with Robertson and Paul Alper (Alper), respondent's business consultant, to discuss the Ferbers' role in the HLW transaction. During that meeting, Robertson was advised that upon closing the Ferbers would receive $100,000 towards one mortgage; $10,000 towards another; $10,000 for living expenses; and a consulting contract with HLW worth $20,000 per year for each year the Liberty mortgage remained a lien on the Ferbers' property. Robertson was also advised that the Ferbers' maximum risk would actually be $180,000 as opposed to $400,000. Liberty would look [***12] first to the $100,000 cash collateral to be pledged by Waters, respondent or HLW, thereby reducing the Ferbers' exposure to $300,000. Additionally, the Ferbers would be receiving $120,000 in cash, thereby further reducing their exposure from $300,000 to $180,000.
"Later that same day, respondent met with Alper and Ferber in Robertson's absence. As a result of that meeting, respondent and Alper submitted a mortgage application on behalf of the Ferbers to Capital Mortgage Company seeking a $10,000 loan for general living expenses. On this application respondent knowingly misrepresented that Fred Ferber earned an annual income of $50,000.

"On May 2, 1979, respondent forwarded to counsel for Liberty much of the documentation required by the April 23, 1979, commitment letter. Copies of these documents were sent directly to Ferber and not to Robertson.

"On May 11, 1979, Robertson sent respondent a letter confirming their discussions during the April 25, 1979 meeting and reviewing certain aspects of the prospectus and agreement of sale. The letter pointed out a number of problems Robertson had with the Ferber financial statement contained in the prospectus. These problems included the gross overvaluation of Ferber's patent rights in 'Protosoil'; the listing of a nonexistent note receivable from HLW in the amount of $100,000; a listing of a nonexistent consulting fee of $18,500 receivable from HLW; the failure to list a mortgage of $120,000; and the listing of accounts payable of only $22,000 instead of the more than $55,000 previously indicated by respondent.

"On May 16, 1979, respondent received a commitment from Manufacturers Hanover Trust for a loan of $65,000 to his law firm. Unbeknownst to Robertson, the loan was to be guaranteed by the Ferbers. When the loan closed on June 29, 1979, Fred Ferber signed his name and forged his wife's signature. Although respondent was aware of the forgery, he did not inform his partner (who acknowledged the two signatures), Manufacturers Hanover or Robertson. In fact, he did not inform Robertson about the loan itself until the day of the HLW closing.

"On May 18, 1979, without prior notice to or consent from Robertson, respondent concluded negotiations with the mortgagee of the 212 acre tract resulting in the subordination of that mortgage to the proposed mortgage of Liberty. The subordination agreement, which respondent signed on behalf of Eastern, raised the interest rate on the remainder of Ferber's indebtedness from 8% to 14%. Upon completion, respondent forwarded a set of the documents to Robertson, advising him that the mortgagee's security interest in the HLW accounts receivable had been increased and that it would be necessary to advance to Ferber the majority of his first two years of consulting fees ($40,000) in order to meet pressing needs.

"On May 24, 1979, after reviewing the 1978 financial statement of HLW prepared by William Kaufman, C.P.A. (Kaufman), Liberty revoked its commitment. Upon receiving notification of the revocation, respondent called Robertson and told him to stop all work. Respondent then wrote a letter to Liberty threatening suit and retained Robert L. McKinstry, Esq., an attorney on the board of directors of Liberty, and James D. Elleman to lobby for reinstatement of the commitment.

"In an attempt to repair the damage caused by the Kaufman analysis, respondent contacted his cousin Herman and had him prepare a report reviewing Kaufman's findings. This report, dated June 1, 1979, concluded that appropriate adjustments to some of Kaufman's figures would project a healthier financial condition. Respondent forwarded this report to Liberty on or about June 4, 1979. After conducting a supplemental

"In early June 1979, Ferber's financial condition deteriorated to a point where he could not meet any of his current obligations. Respondent contacted Peter F. Mento, Jr. (Mento), a director of Interchange State Bank (Interchange), and negotiated a $3,000 loan to cover Ferber's living expenses. This loan, the proceeds of which were paid to respondent as trustee, was for a term of six months with an interest rate of 15%. As security, Ferber was required to execute a note and mortgage against his 18 acre property in West Milford Township. Respondent did not inform Robertson of this transaction.

"Respondent next turned his attention to the task of obtaining the $100,000 cash collateral required by Liberty. With the assistance of Alper and Anthony Santangelo (Santangelo), respondent approached a group of entrepreneurs collectively known as the Weir Group (Weir or Weir group). At a meeting held on June 7, 1979, Weir requested financial information. Respondent provided the original prospectus, the 1978 HL W financial statement prepared by Kaufman, the Ferber financial statement prepared by Herman dated April 30, 1979 and the 1976 and 1977 HL W financial statements.

"At the time he provided Weir with the requested documentation, respondent knew that much of the information contained therein was false and misleading. As previously indicated, the prospectus grossly exaggerated Ferber's assets and severely underestimated his liabilities. Similarly, the Ferber financial statement prepared by Herman falsely indicated that Ferber owned a note receivable in the amount of $100,000 from HLW and was to receive a consulting fee of $18,500 from HLW as well.

"Most egregious, the 1978 HLW financial statement prepared by Kaufman was altered by respondent before delivery to Weir. Knowing that this financial statement had in large part been responsible for the revocation of the Liberty commitment, respondent feared it would have a similar effect on the Weir Group. Therefore, certain pages were removed and others substituted. The original statement showed a net income figure of $140,554 for the year ending December 31, 1978. Respondent removed the page containing that information and substituted one of his own showing a total net income of $524,132. The original financial statement also contained a page embodying a Statement of Changes in Financial Position. Since that page made reference to the net income figure of $140,554, respondent removed it, making no substitution. Respondent told no one about this alteration. At the civil trial, respondent testified that he was unaware that the financial statement had been altered.

"On June 11, 1979, the Weir Group issued a commitment letter to Eastern for a two year loan in the amount of $100,000 at 25% interest. The commitment required that the Weir Group receive a third mortgage on the 212 acre property; a second mortgage on a 113 acre property also owned by the Ferbers; a financial statement showing the Ferbers' net worth to be not less than $1,000,000; the Ferbers' personal guarantees of the loan; and a security interest in HLW's accounts receivable. In a side agreement it was also stipulated that the Weir Group would receive a 15% interest in HLW as additional compensation. At no time did respondent advise the Weir Group that Liberty had revoked its commitment on May 24, 1979 and had not reinstated same until June 15, 1987. When respondent negotiated this loan and ultimately signed the commitment papers
In an effort to obtain additional funding, respondent enlisted Mento's aid in securing a $60,000 loan from his bank. In exchange for a finder's fee of $3,600 plus an 8% interest in HLW, Mento agreed to assist in the placement of a loan with Interchange, where Mento served on the board of directors. On June 12, 1979, Mento issued a commitment letter to Eastern on Interchange stationery for a $60,000 loan payable in two years at 20% interest. Pursuant to the commitment, Interchange was to receive as security a second mortgage on the Ferbers' 18 acre property in West Milford, the Ferbers' personal guarantees of the loan and a sinking fund of HLW receivables. However, Interchange was not aware of and had not authorized Mento's commitment letter. Consequently, respondent and Mento entered into a side agreement which provided that respondent would not hold Mento liable on the Interchange commitment letter.

"On June 12, 1979, in order to comply with a deadline [***19] previously set by Waters' attorney, respondent sent this attorney a letter outlining his sources of funding for the acquisition. In this letter respondent indicated that he would be receiving $400,000 from Liberty; $100,000 from the Weir [***1232] Group; $65,000 from Manufacturers Hanover Trust; and $60,000 from Interchange. Respondent enclosed copies of the April 23, 1979 commitment letter from Liberty, the June 11, 1979 commitment letter from the Weir Group and the June 12, 1979 commitment letter from Interchange. He did not indicate that Liberty had revoked its commitment on May 24, 1979 or that the Interchange commitment was unauthorized. Nor did he provide Robertson with copies of the June 12, 1979 letter to Waters' counsel or the commitment letters from Liberty, the Weir Group and Interchange.

"On June 15, 1979, Liberty reinstated its commitment to lend Eastern $400,000. Upon receiving notification of the reinstatement, respondent contacted Robertson and advised him that the transaction was still very much alive and that work could continue. Robertson renewed his request for copies of all documents related to the acquisition but respondent failed to honor this request.

[***20] "On June 20, 1979, respondent called Robertson with some of the details of the transaction Robertson had been requesting. Specifically, he advised Robertson that the Weir Group was making a $100,000 loan payable in two years; Waters had agreed to subordinate his lien on HLW's accounts receivable to the extent of $265,000; the Ferber's lien on the accounts receivable would exist through the mortgagee's lien; and Ferber would receive $140,000 at closing with $100,000 payable to the mortgagee and $40,000 representing the first two years of consulting fees payable to Ferber. Respondent also claimed that Ferber would have absolutely no exposure because he would be receiving a $165,000 lien on HLW accounts receivable through the mortgagee's lien. As respondent explained it to Robertson, Ferber's gross maximum exposure was $300,000 ($400,000 less the $100,000 cash collateral). Since Ferber was receiving $140,000 at closing, the balance of his exposure would be $160,000, which would be totally protected by Ferber's subordinated lien on the HLW receivables through the mortgagee.

"The exact date and time of the closing was undetermined until June 21, 1979. On that date Ferber [***21] called Robertson and advised him that the closing was to take place on the following day, June 22, 1979. Ferber also gave Robertson a telephone number at which
respondent had told Ferber he could be reached. However, despite numerous attempts, Robertson was unable to reach him.

"On June 22, 1979, at 9:15 a.m., Robertson was finally able to reach respondent. At that time, Robertson advised respondent that since he had not been provided with all relevant paperwork, he had not had an opportunity to prepare a formal agreement between the Ferbers and respondent. Moreover, because he would not be available until later that afternoon, the closing would have to take place in escrow. Respondent assured Robertson that he would make his position known to all parties concerned. Respondent then advised Robertson of certain changes that had been made in the structure of the deal.

"Upon completing his conversation with Robertson, respondent, Herman and the Ferbers left for New York City to attend the closing. Immediately upon their arrival, respondent's associate took the Ferbers to a private social club. During the morning session of the closing, with Robertson unavailable, and in the [***22] Ferbers' absence, numerous provisions of the deal protecting the Ferbers were eliminated.

"Later that afternoon, it became obvious that the closing could not be held in escrow. Liberty had taken the position that respondent had to become owner of HLW in order to have the cash flow upon which the bank was relying as a condition of the loan. However, Waters would not transfer title unless and until he was paid. In addition, the mortgagee on the 212 acre tract needed his money immediately to meet other commitments and promised to foreclose if he did not receive the money as promised.

"At that point a telephone conversation was held among respondent, Robertson, Ferber and the other parties' representatives. Robertson reiterated that since he [***1233] had not had an opportunity to review any of the paperwork, he could not advise his clients to go through with the closing. However, Ferber was under a great deal of pressure to close and insisted that Robertson find a way [*204J to allow the closing to proceed to conclusion. After further negotiations, it was finally agreed that Robertson would draft a short form agreement between Ferber and respondent which he would dictate to a secretary [***23] in the closing office. Robertson again advised Ferber that this approach was inherently risky and that the better course would be to postpone the closing for a few days until he had an opportunity to review all of the papers. Nevertheless, Ferber stated that he was willing to rely on respondent's good judgment and would complete the closing upon execution of the short-form agreement which would contemplate revisions and additional documents.

"Sometime after 5 p.m. that afternoon, Robertson dictated a formal agreement which was ultimately signed by Ferber and respondent. Based upon Robertson's limited understanding of the various components of the transaction, the agreement contained the following provisions: (1) respondent was to pay $100,000 toward the mortgage on the 212 acre property; (2) Ferber was to receive a consulting contract paying $20,000 per year for as long as the Liberty lien remained in effect; (3) respondent was to assign a life insurance policy with a cash surrender value of at least $40,000 to Ferber as security; (4) the $100,000 cash collateral was to be the primary asset to which Liberty would resort in the event of a default and was not to be released [***24] without the Ferbers' consent; (5) Waters' lien on HLW's assets was to be subordinated to a security interest in HLW's accounts receivable in favor of the mortgagee and Weir in the amount of $265,000 which, in turn, was to provide
that the Ferbers would have a primary security interest in these receivables by assuming the position of the mortgagee and Weir as their indebtedness was satisfied; (6) Liberty was to release the mortgage on the 212 acre property as soon as the total debt fell below the sum of $100,000; and (7) there had been no material adverse change in the financial condition of HLW since December 31, 1978.

"Unbeknownst to Robertson, shortly before executing this agreement with Ferber, respondent executed a closing agreement with Waters which specifically stated that there had been material adverse changes in the financial condition of HLW since November 15, 1978 due to the loss of a number of important clients and key employees. Additionally, before executing the agreement with Ferber, respondent unilaterally changed the amount of Ferber's security interest in HLW's accounts receivable from $265,000 to $165,000.

"At closing, respondent also agreed to two modifications [***25] of the June 11, 1979 side agreement proposed by the Weir Group. Pursuant to the initial modification, respondent delayed creation of the Weir Group's 15% interest in HLW until Waters was paid in full and agreed to pay the Weir Group $200,000 annually from HLW profits if the proposed partnership were not formed within four years. According to the second modification, respondent agreed to provide a principal of Weir with a four-year 'consulting contract' worth $227,500, the proceeds of which were to inure to the benefit of the Weir Group. In reality, this consulting contract was a subterfuge designed to circumvent the provision in the sale agreement prohibiting any assignment of respondent's interest in HLW while the purchase price remained unpaid. Respondent agreed to these two modifications without first advising or securing the consent of Robertson or Ferber.

[*205] "All of the elements of the HLW transaction, with the exception of the $65,000 loan from Manufacturers Hanover Trust and the $60,000 loan from Interchange/Mento, closed on June 22, 1979. The Manufacturers Hanover note, guaranteed by the Ferbers and payable on demand at 1 1/2 points over prime, was executed [***26] on June 26, 1979. Respondent did not inform Robertson of that closing or of the fact that the Ferbers had guaranteed the note. The Interchange/Mento loan closed on July 12, 1979, at which time respondent signed a [**1234] note obligating HLW, Eastern and himself to Mento. The proceeds of this loan were paid to Chemical Bank in discharge of one of respondent's obligations under the original agreement of sale. Respondent did not disclose the existence of this transaction to Robertson or Ferber, nor did respondent ever advise Robertson of the nature or extent of the finder's fees he had awarded to several other individuals.

"In or about mid-1980, although current on its payments to Liberty and the Ferbers, HLW fell behind on its obligations to the Weir Group, Mento and numerous trade creditors. Consequently, a group of creditors formed a creditors' committee. This committee, which in effect became a board of directors, assumed complete control over all financial decisions. Nevertheless, due to the overwhelming amount of debt incurred as a result of the transaction, HLW was compelled to file for bankruptcy in March 1981. As a result of the failure of HLW, the Ferber estate (Fred and Hedwig [***27] both died prior to the conclusion of the bankruptcy proceedings and related lawsuits) lost $267,500; the Weir Group lost $69,000; and the Mento estate (Peter Mento also died prior to the conclusion of the various legal proceedings) lost $
Respondent contended the failure of HLW was caused by Waters' fraudulent misrepresentations regarding its assets and liabilities; in the bankruptcy litigation Waters was sued by the trustee and settled the action with a payment of $50,000. Meanwhile, in consolidated civil proceedings, Liberty sought to foreclose against the 212-acre West Milford property that had been transferred to Eastern, while the Ferbers' estates asserted claims against Silverman for fraud and sought to invalidate the various mortgage agreements and Eastern debts. In that action Liberty recovered the full amount of the loan, and the Ferbers were awarded a $267,500 judgment against Silverman covering all losses to the estates. As of April 1987 respondent, through continuing monthly installments of $400 to $600, had paid off approximately $30,000 of the outstanding liabilities. 1

1 Although the Board found that $145,000 of the judgment was satisfied by other defendants, the record is unclear on whether this $145,000 payment to the Ferbers' estates represented independent damages or was credited to Silverman's liabilities.

On June 24, 1982, shortly after judgment had been rendered in the civil action, respondent consented to a voluntary suspension of his plenary license to practice. The Patent and Trademark Office, however, authorized respondent to continue practicing in agency matters, pending final outcome of this proceeding. Since then respondent has practiced before the Patent and Trademark Office without incident. 2

2 In the interim respondent has also taken and passed the Florida State Bar examination, including the required multi-state professional responsibility exam. Respondent stated that he awaits final judgment in this matter before applying for admission to the Florida bar.

[***29] In order to simplify the proceedings before the District Ethics Committee, respondent and the OAE prepared a stipulation laying out the transaction and respondent's role. The stipulation included respondent's acknowledgment that the facts and conclusions "demonstrate unethical conduct * * * which warrants public discipline." Subsequently, on November 19, 1986, the Ethics Committee commenced a hearing at which only respondent testified, and thereafter issued a presentment recommending public discipline. The presentment, dated February 27, 1987, charged that respondent had entered into a business transaction with a client who was relying on him to exercise his professional judgment, without making full disclosure or obtaining proper consent, in violation of DR 5-104(A), and that numerous instances of his conduct throughout the transaction amounted to violations of DR 1-102(A)(3) and (A)(4), rules proscribing, respectively, conduct "that adversely reflects on * * * fitness to practice law" and that "involv[es] dishonesty, [*207] [*1235] fraud, deceit, or misrepresentation." 3 However, the Committee rejected charges that respondent had perjured himself before the client security [*30] fund and/or in the consolidated civil proceedings. Further, notwithstanding claims of the OAE to the contrary, the committee ruled that DR 5-101(A), a provision barring the acceptance of employment under circumstances likely to result in a conflict, was inapplicable due to the absence of any "factual basis for the conclusion that [respondent] affirmatively undertook to represent" anyone other than himself in the HLW acquisition.

3 The Committee properly looked to the former Disciplinary Rules, since the relevant events occurred prior to the effective date of the new Rules of Professional Conduct, September 10, 1984.

The Disciplinary Review Board agreed with Committee's findings concerning DR 1-102(A)(3), (4) and DR 5-104(A), but differed with respect to its conclusions regarding respondent's alleged violations of DR 5-101(A):

The Board, however, does not agree with the committee's finding that there was no affirmative undertaking by respondent to represent Ferber and, therefore, no violation of [*31] DR 5-101(A). Representation is inherently a consensual relationship founded upon the lawyer affirmatively accepting a professional responsibility. Such "acceptance need not necessarily be
articulated in writing or speech but may, under certain circumstances, be inferred from the conduct of the parties." In re Palmieri, 76 N.J. 51, 58-59 (1978).

When respondent first discussed the acquisition of HLW with Ferber in January 1979, Ferber's status was that of an occasional client. In fact, at that particular point in time, Ferber owed respondent's law firm a substantial amount of legal fees which had been incurred in the process of securing the "Protosol" patent. Ferber was 75 years old, broke in terms of spendable cash and in default on numerous debts, including mortgage and real estate tax payments on his rather substantial land holdings. In particular, Ferber was in default on secured and unsecured loans to the mortgagee who held a first mortgage on the 212 acre property. Ferber was also in default on a first mortgage on a 31 acre property which was in foreclosure.

Ferber was willing to allow respondent to use his property as collateral in exchange for money with which to live. Therefore, respondent engaged in many attempts to forestall execution of the foreclosure and the institution of additional foreclosure actions until the HLW closing, when the liens on Ferber's properties were to be paid. Although respondent claims he did not represent Ferber in connection with the existing and potential actions, and was acting solely as a co-venturer to "keep the wolves from Ferber's door" for as long as possible, these negotiations with the lien-holders and additional actions taken on the Ferbers' behalf were indicative of an attorney-client relationship.

There can be no doubt, for example, that respondent was acting in his capacity as an attorney for the Ferbers and/or Eastern when he prepared the deed conveying title to the 212 acre property from the Ferbers to Eastern and then drafted the corporate resolutions necessary to facilitate the transaction. Nor can there be any doubt that respondent was also acting in his capacity as Ferber's attorney when, in June 1979, he negotiated with Mento to secure a $3,000 loan to meet Ferber's living expenses. Although it is not clear whether respondent formally drafted the mortgage and notes securing the loan, he negotiated the terms of the loan and advised Ferber to execute the documents. There is no evidence that respondent fully disclosed to Ferber the full extent of his own financial, business and personal interests in these numerous transactions.

Moreover, respondent continued to act as Ferber's de facto attorney even after Ferber retained Robertson as his independent counsel. Although he advised Ferber to retain his own attorney, he repeatedly ignored Robertson and continued to work and communicate directly with Ferber. Respondent's intentional failure to provide Robertson with essential information, as well as his continuous discussions with Ferber, fostered an environment in which Ferber could turn only to respondent for advice, particularly at a time when their respective interests were in obvious conflict. Consequently, the Board concludes that respondent violated DR 5-101(A) in that he affirmatively represented Ferber when he knew or should have known that his representation would be affected by his own personal interests and failed to fully disclose this fact to his client.

The Board also disagreed with the Committee's rejection of the OAE's assertion that respondent had perjured himself, finding that "the record * * * demonstrates that respondent, on more than one occasion, knowingly made false statements under oath to avoid liability for his actions." Its findings in this regard were based on a comparison between portions of respondent's
testimony before the Client Security Fund and in the aforementioned consolidated civil proceedings, and statements in the stipulation:

Respondent intentionally withheld the June 12, 1979 letter outlining his sources of funding from Robertson because of his fear that upon examining same Robertson would advise Ferber to withdraw from the transaction. Although he did give a copy of this letter to Ferber, respondent knew Ferber would not understand or appreciate its importance and, therefore, would not forward it to Robertson. In fact, in his testimony before the committee, respondent admitted that he had conveyed his misgivings about Robertson to Ferber and that Ferber had said he would "take care of him." Based upon this conversation with Ferber, respondent was confident Ferber had no intention of providing Robertson with any information regarding the transaction.

However, in prior testimony at the civil trial, respondent testified that he had assumed Ferber would deliver the letter to Robertson and had, in fact, instructed him to do so. Then, in subsequent proceedings before the Trustees of the Clients' Security Fund, respondent testified that he had had no reason to believe Ferber would fail to deliver the letter or reveal its contents to Robertson. When confronted with these inconsistent statements, respondent was constrained to admit his testimony before the Clients' Security Fund "could have been expressed, perhaps, with greater candor" and that "the Stipulation (entered into with the Office of Attorney Ethics) is a more candid expression of what I knew of Ferber's modus operandi with Robertson." More importantly, when questioned about his statements at the civil trial, respondent fully admitted that his "testimony was false, it's shaded, it was not as candid as the subsequent testimony."

Respondent was also less than truthful in his prior testimony concerning the sanitizing of the 1978 HLW financial statement prepared by Kaufman. Although he had personally deleted the two pages referring to the net income figure of $140,544 and substituted the page showing a net income figure of $524,132, at the civil trial respondent testified that he had been totally unaware of the document had been altered. When confronted with this statement at the hearing before the district ethics committee, respondent denied having perjured himself but allowed that his civil testimony "would have to be somewhat changed in its shading."  

As discussed infra at 222-224, the Board's characterizations of respondents' testimony in the civil proceeding and in the Committee hearing regarding the alteration of the Kaufman statement are incorrect. The record in the civil proceeding reveals that at one point respondent acknowledged changes in the Kaufman statement. Moreover, before the Committee respondent's testimony was that the statement in the stipulation concerning his testimony "would have to be somewhat changed in its shading," and not, as the Board asserted, the civil testimony itself.

Turning to the appropriate discipline, the Board noted respondent's contention that his conduct was affected by his "obsession" and "frenzy" to purchase HLW, but discounted its significance. Citing its findings concerning respondent's allegedly false testimony, the Board reasoned that his "unethical behavior was not limited to this one 'unfortunate period' in 1979." In sum, the Board concluded that despite respondent's prior unblemished record, the totality of his misconduct leaves us without any confidence that respondent could ever again practice law in conformity with the standards of the profession, and consequently, recommended disbarment.

II

Ten years ago this Court reiterated Justice Jacobs' advice "that society might be 'better served if practicing attorneys were to remain full-time lawyers rather than..."
become part-time businessmen."" In re Palmieri, 76 N.J. 51, 53 (1978) (quoting In re Carlsen, 17 N.J. 338, 346 (1955)). This warning was premised on the fact that attorneys who choose to engage in commercial pursuits do not "shed in chameleon fashion" their status and concomitant professional obligations. In re Carlsen, supra, 17 N.J. at 346. Rather, [**38] such "[a]ttorneys are held to a higher standard than that of the market place * * * [and their] conduct must measure up to the high standards required of a member of the bar even if [their] duties in a particular transaction do not involve the practice of law." In re Reiss, 101 N.J. 475, 488 (1986); accord In re Smyzer, 108 N.J. 47, 57 (1987); In re Hurd, 69 N.J. 316, 330 (1976).

DR 1-102(A)(3), (4)

Our independent review of the facts admits of no conclusion other than that respondent committed numerous ethical transgressions, demonstrated by clear and convincing evidence in the record. In his zeal to obtain adequate financing to consummate the acquisition of HLW, respondent prepared various statements and documents containing knowing misrepresentations of highly material facts. For example, in the prospectus, containing both his and Ferber's financial statements, and on the Liberty Loan application, respondent exaggerated or created non-existent assets and ignored or understated significant liabilities. Respondent altered the net income figure of the Kaufman 1978 HLW financial statement and, along with [**39] the prospectus, submitted it to the Weir group; respondent also altered, without Ferber's knowledge, a key figure on the closing memorandum agreement dictated by Robertson.

[**211] Further, several misrepresentations were effected by omissions on respondent's part: (1) in his June Twelfth letter to Waters respondent enclosed the Liberty commitment letter without disclosing that it had been revoked; (2) at the closing respondent signed the Robertson memorandum, which stated inter alia that there had been no material adverse change in HLW's financial condition since the first of the year, but failed to reveal that he had executed an agreement with Waters acknowledging the alleged existence of such adverse change; and (3) respondent withheld from Ferber and Robertson many of the details concerning side agreements he had made with Mento, Weir, and others that affected the stability of HLW. Respondent also acquiesced in Ferber's forgery of his wife's signature on the Manufacturers Hanover loan guarantee.

These omissions and affirmative misrepresentations, intended by respondent to induce favorable decisions by the various parties, were egregious and fraudulent and constituted [**40] clear violations of DR 1-102(A)(4). Moreover, several of these incidents were, in all likelihood, criminal acts adversely reflecting on respondent's fitness to practice, and thus constituted independent violations of DR 1-102(A)(3). See [**1238] N.J.S.A. 2C:21-7 h (fourth degree offense to "make a false or misleading statement for the purpose of obtaining * * * credit"); N.J.S.A. 2C:21-1 a(1-3) (fourth degree offense to (1) alter or change "the writing of another without his authorization," or to utter a writing known to have been executed "so that it purports to be the act of another who did not authorize that act.").

5 "A lawyer shall not * * * [e]ngage in conduct involving dishonesty, fraud, deceit, or misrepresentation." Rule 8.4(c) of the Rules of Professional Conduct is nearly identical.

6 "A lawyer shall not * * * [e]ngage in illegal conduct that adversely reflects on his fitness to practice law." Rule 8.4(b) of the Rules of Professional Conduct proscribes the commission of criminal acts that reflect adversely on a lawyer's "honesty, trustworthiness or fitness as a lawyer in other respects."

[**41] [*212] Respondent offers various asserted justifications and explanations for these actions. At the Committee hearing respondent testified that while at the time he prepared the prospectus he realized Ferber had apparently supplied him with false financial information, it was not until Robertson became involved that he "had any way of knowing definitely, absolutely." And then, despite written notification from Robertson regarding specific errors, respondent stated, "I was not about to say to Liberty 'please revoke your commitment. There's been a material misrepresentation in Ferber's net worth,' particularly in that Liberty had their own appraisal done of the collateral property." Concerning the alterations of the Kaufman financial statement, respondent testified that he felt the use of a cash basis to compute HLW's 1978 net income represented "a calculated effort [by Waters' attorney] to torpedo the transaction," and that the new figures, derived from an accrual basis analysis provided to respondent by his accountant, were legitimate. Further, with respect to the alteration of the closing
memorandum prior to Ferber executing it, respondent suggested that the figures supplied by Robertson were based on a miscalculation of Ferber's unsecured exposure on the loan, and that Robertson himself had previously assented to the validity of the corrected figure. Finally, as far as his failure to tell Ferber and Robertson of the Waters' closing memorandum alleging that adverse change in HLW's finances had occurred, respondent expressed that he considered the change immaterial, such that the "no material change" representation in the Robertson closing memorandum was more accurate.

Quite clearly, respondent's rationalizations for these acts are unavailing, and neither lessen their seriousness nor constitute a defense. DR 1-102(A)(4) simply proscribes conduct that knowingly is dishonest, fraudulent, deceitful, or involves misrepresentation. E.g., In re Kotok, 108 N.J. 314, 327 (1987) (providing knowingly false answer on handgun permit application, even if not done with "obvious purpose to mislead," violates DR 1-102(A)(4)); see In re Servance, 102 N.J. 286, 294 [*213] (1986) (DR 1-102(A)(4) violated where attorney represented investments were sound although "he knew little or nothing about them"). "A [***43] lack of honesty is a serious character flaw, intolerable in the professional makeup of an attorney." In re Pleva, 106 N.J. 637, 645-46 (1987). Respondent's personal belief that the information he misrepresented and/or concealed from the other parties was insignificant under the circumstances no more negates the improper and unethical nature of these acts than does the fact that an attorney who misappropriated client funds merely intended to borrow rather than steal. See, e.g., In re Warhaftig, 106 N.J. 529, 533-34 (1987); In re Noonan, 102 N.J. 157, 159-160 (1986).

As for preparation of the prospectus and financial statements, even if we credit respondent's testimony that at the time he only suspected Ferber had provided him with incorrect financial information, his decision to submit the documents to Liberty without even attempting to verify the validity of such information evinces a sufficiently reckless disregard for the truth of the prospectus to constitute dishonest and deceitful conduct. E.g., In re Servance, supra, 102 N.J. at 294; In re Walk, 82 N.J. 326, 329 (1980). [***44] Furthermore, respondent misrepresented information concerning his own financial position on the prospectus.

DR 5-104(A)

We also find, as did both the Committee and the Board, that respondent's entire course of conduct in dealing with Ferber clearly violated DR 5-104(A), a rule instructing that lawyers "shall not enter into a business transaction with a client if they have differing interests therein and if the client expects the lawyer to exercise his professional judgment therein for the protection of the client, unless the client had consented [*214] after full disclosure." 7 Although at the time respondent first discussed the HLW transaction with Ferber he was not actively representing him in a specific matter, it is clear that the two related to each other generally as attorney and client. It is also clear that it is the substance of the relationship, involving as it does a heightened aspect of reliance, that triggers the need for the rule's prescriptions of full disclosure and informed consent. See In re Walk, supra, 82 N.J. at 332-33; In re Makowski, 73 N.J. 263, 268-69 (1977); In re Hurd, 69 N.J. 316, 329-330 (1976). [***45] Hence, there is little doubt that respondent engaged in a business transaction with a client; indeed, he conceded as much in his testimony before the Committee when he stated that he felt Robertson's appointment "removed [him] from the attorney role vis-a-vis Ferber."

7 Rule 1.8(a) now governs this particular area of professional responsibility, in a somewhat stricter manner:

A lawyer shall not enter into a business transaction with a client or knowingly acquire an ownership, possessoriy, security or other pecuniary interest adverse to a client unless (1) the transaction and terms in which the lawyer acquired the interest are fair and reasonable to the client and are fully disclosed and transmitted in writing to the client in manner and terms that should have reasonably been understood by the client, (2) the client is advised of the desirability of seeking and is given a reasonable opportunity to seek the advice of independent counsel of the client's choice on the transaction, and (3) the client
The dynamics of the transaction clearly gave rise to differing interests on Ferber's and respondent's behalf, as the two were in effect aligned, respectively, as lender and borrower. See In re Smyzer, supra, 108 N.J. at 54-56 (differing interests involved where attorney counseled clients to invest in financially-troubled companies in which he held an interest); In re Wolk, supra, 82 N.J. at 333-34 (DR 5-104(A) applicable where client invested $10,000 on second mortgage for rental property owned in part by attorney); In re Makowski, supra, 73 N.J. at 267-69 (DR 5-104(A) applied to loans from client to attorney).

Further, Ferber was undoubtedly relying throughout on respondent's good judgment; the record reveals that even at the [*215] closing, long after Robertson had been retained, Ferber felt he could act on respondent's advice. Cf. In re Servance, supra, 102 N.J. at 294 (history of honesty and faithfulness leads clients to trust attorneys with their property); In re Palmieri, supra, 76 N.J. at 59 (evidence failed to support any inference that asserted [*47] client relied on respondent "in any professional capacity"). Before the Committee respondent conceded that although at the time of the transaction he viewed Ferber strictly as a co-venturer, in retrospect "there can be no question" that Ferber relied upon him in a personal capacity and as an attorney.

Hence, inasmuch as respondent entered a business transaction with a client, where the two had differing interests and the client relied on him to exercise good judgment for the client's protection, it was incumbent on him to make full disclosure concerning all aspects of the transaction. E.g., In re Smyzer, supra, 108 N.J. at 54-56; In re Wolk, supra, 82 N.J. at 332-34; In re Makowski, supra, 73 N.J. at 268-69. Unlike the concealment involved in Smyzer, supra, respondent's interest in the HLW transaction was fully disclosed. However, from the onset of negotiations with Ferber he failed to reveal important details of his arrangements with the other parties, details that significantly affected HLW's prospective cash flow and thus directly related to the financial soundness of the deal as far [*48] as Ferber's interests were concerned. 8 See In re Wolk, supra, 82 N.J. at 332 [*48] (DR 5-104(A) violated where respondent told client of interest in transaction but failed to disclose crucial, adverse [*216] financial information); In re Makowski, supra, 73 N.J. at 269 (failure to disclose specifics of loan transactions with client violates DR 5-104). Respondent thus clearly failed to "take every possible precaution in ensuring that his client [was] fully aware of the risks inherent in the proposed transaction." In re Smyzer, supra, 108 N.J. at 55.

8 For example, respondent failed adequately to disclose the following details to either Robertson or Ferber: (1) Various finders fees to be paid out of the HLW cash flow, (2) the necessity to secure the Weir loan with second and third mortgages on various Ferber properties, and (3) arrangements with the Weir Group involving substantial payments in lieu of a promised 15% interest in HLW. Respondent's contention that these omissions were harmless because there was no equity in the land left to mortgage, and because the promised payments were subordinated to Ferber's security in the HLW cash flow are wholly unpersuasive. See infra at 216.

[*49] Respondent of course did, sometime in mid-April 1979, advise Ferber to retain independent counsel. The fundamental ethical objective at stake, however, dictates that such advice should have been given to Ferber in January 1979 when the two first discussed the possibility of joint participation in acquiring HLW. See Smyzer, supra, 108 N.J. at 54-55 (attorney contemplating business transaction with client "must carefully explain * * * the need for independent legal advice"); In re Wolk, 82 N.J. at 334 (counsel "should have insisted" client retain independent counsel); In re Hurd, 69 N.J. at 329 (although no attorney client relationship existed, counsel should have refused to go forward with transaction until independent legal advice had been obtained). As we explained in Wolk, supra:

Lawyers have a duty to explain carefully, clearly and cogently why independent legal advice is required. When a lawyer has a personal economic stake in a business deal, he must see to it that his client understands that his objectivity and his ability to give his client undivided loyalty may be affected. [*50] [82 N.J. at 333.]

Here the record reveals that before respondent advised Ferber to retain independent counsel, the two had
negotiated the specifics of Ferber's end of the deal and implemented the transfer of Ferber's real estate to Eastern. Further, respondent had allowed Ferber to participate in the submission of the fraudulent prospectus to Liberty. The importance of obtaining outside counsel prior to these events is painfully clear. Cf Wolk, supra, 82 N.J. at 334 (noting pitfalls of transaction that independent counsel would have discovered).

Nor did Ferber's retention of Robertson cure respondent's violation of DR 5-104(A), since his subsequent concealment of material information effectively neutralized Robertson's usefulness to Ferber. Cf Smyzer, supra, 108 N.J. at 55 (disclosure [*217] requirement not satisfied by pro forma suggestion regarding outside counsel); In re Wolk, supra, 82 N.J. at 333 (rejecting sufficiency of advice concerning outside counsel "designed to protect [respondent] rather than his client"). Respondent's decision to withhold financial data [***51] because he felt that they (a) were unimportant as far as Ferber's interests, or (b) would lead Robertson to "torpedo the deal," preempted the precise tasks outside counsel is charged with in such situations. The Rule pre-supposes that counsel's interest in the transaction renders him objectively incapable of deciding what information is important as far as his client/co-venturer's interests are concerned, and whether or not he should consummate the transaction. Rather, these tasks are best left to outside counsel, who should advise against moving forward if it is determined that the transaction is not in the client's best interests.

DR 5-101(A)

The Board, as noted above, rejected the Committee's finding that no specific attorney-client relationship existed concerning the HLW acquisition, and concluded that aside from DR 5-104(A) respondent had also violated DR 5-101(A). Supra at 207-209. This rule focuses on the propriety of an attorney-client relationship itself, and requires full disclosure and client's consent if the lawyer's professional judgment concerning [**1241] the subject matter of the employment relationship "will be or reasonably may be affected by his own [***52] financial, business, property, or personal interests." DR 5-101(A). 9

9 This Rule is now covered by RPC 1.7(b).

In addressing this issue the Board properly looked to In re Palmieri, supra, where, while noting that representation is essentially "an aware consensual relationship," we stressed that an attorney's acceptance of obligations in his professional capacity "need not necessarily be articulated, in writing or speech but may, under certain circumstances, be inferred from the conduct of the parties." 76 N.J. at 58-59; see In re Makowski, supra, 73 N.J. at 268-69. The Ethics Committee concluded that in seeking to acquire HLW respondent represented no one but himself, and further, found no factual basis to infer any affirmative undertaking to represent Ferber. The Committee expressed the view that

[***53] the gravamen [sic] of respondent's improper conduct concerning Ferber was the entry into a business transaction with Ferber without [***53] the latter having separate counsel and while Ferber was relying upon respondent for advice. We distinguish such from an affirmative undertaking by respondent to represent to Ferber as to which we find no such facts.

However the Board, citing respondent's attempts to delay adverse action by various mortgagees, attempts to help Ferber obtain additional mortgage monies, and preparation of the deed and corporate resolutions involved in transferring the property to Eastern, concluded that respondent had "affirmatively represented" Ferber.

Although the matter is not free from doubt, on a close and careful examination of the record we differ with the Board to the extent it determined there was an attorney-client relationship between respondent and Ferber with respect to the transaction itself. We conclude that the existence of such a specific professional relationship within the meaning of DR 5-101(A) is not supported by clear and convincing evidence. However, limited to the specific matters cited by the Board, we agree that respondent entered into an attorney-client relationship with Ferber.

Looking first at Ferber's participation in the transaction, the record neither suggests [***54] that any express employment agreement existed between the two, nor does it sufficiently establish a professional relationship by implication. See In re Palmieri, supra, 76 N.J. at 59 (proof insufficient to infer existence of attorney client relationship). Respondent had never performed
corporate or commercial work for Ferber; indeed Ferber knew he practiced exclusively in the field of patents. Moreover, Ferber knew from the outset that the objective of the transaction was to procure sufficient financing for respondent [*219] to purchase HLW. Thus whether or not Ferber was a sophisticated businessman, as respondent contends, it is difficult to imagine that Ferber could reasonably have assumed respondent was acting as his attorney in negotiating the terms of the acquisition. Cf. Ellenstein v. Herman Body Co., 23 N.J. 348, 353 (1957) (noting importance of inferring what parties contemplated in deciding whether a professional relationship was established). Compare In re Wolk, supra, 82 N.J. at 330-35 (no DR 5-101(A) violation found where client knew of attorney's interest in transaction) with In re Makowski, supra, 73 N.J. at 267-69 (***55) (finding attorney-client relationship and violation of DR 5-101(A) where client was wholly unaware of counsel's interest in investments). The hypothesis that the parties contemplated that respondent would act as Ferber's counsel regarding his participation in the transaction is further rebutted by Ferber's subsequent decision to retain Robertson, and indeed by evidence indicating that even before obtaining Robertson as independent counsel Ferber had sought other outside legal and financial advice.

However, we find that an attorney-client relationship did arise by implication regarding the collateral matters cited by [***1242] the Board. Respondent's preparation of the deed and corporate resolutions used to transfer Ferber's property to Eastern were peculiarly legal tasks carried out by respondent primarily for Ferber's benefit, i.e., so that Ferber could carry out his side of the bargain by mortgaging his land. Respondent's undertaking to provide the requisite legal skills for Ferber triggered the obligations of a professional relationship. In re Makowski, supra, 73 N.J. at 269 (citing Shoup v. Dowsey, 134 N.J. Eq. 440, 475-80 (Ch. 1944)). [***56]

Respondent's actions in negotiating with various mortgagors in order to delay action in foreclosure proceedings and in seeking a small loan for Ferber are more difficult to evaluate, as they were activities that a lay co-venturer could rightfully pursue in the interest of furthering the enterprise. The mere [*220] fact that these activities are often undertaken by an attorney acting in his professional capacity does not in itself, in such a situation, create an employment relationship. Cf. Ellenstein v. Herman Body Co., supra, 23 N.J. at 352 (attorney-client relationship not created simply because attorney deploys legal knowledge in completing work "which inherently is not the practice of law"). We are convinced, however, that Ferber believed respondent would exercise his legal skills for his benefit in carrying out these collateral tasks, and effectively relied on him to act as his attorney. Cf. In re Palmieri, supra, 76 N.J. at 60 (imposition of professional obligations requires "identifiable manifestation" that client relied on attorney in his professional capacity).

Nevertheless, despite our agreement with the Board that [***57] respondent entered into a limited professional relationship concerning these various matters, we do not find that such representation violated DR 5-101(A). As noted above, Ferber was aware of respondent's role as a principal from the outset, but was satisfied with respondent's professional role in these tasks. Thus, Ferber impliedly consented to the limited attorney-client relationship. Further, with regard to these specific ministerial tasks, there is no evidence that Ferber's and respondent's interests were different. Therefore, we are not persuaded that there was, or reasonably could have been, an adverse effect on respondent's professional judgment. 10 Hence, we cannot conclude by clear and convincing evidence that respondent's actions in carrying out these collateral tasks violated DR 5-101(A).

10 Had respondent undertaken affirmatively to represent Ferber in the transaction itself, the effect on his professional judgment would be clear. See supra at 214.

False Swearing

We partially differ [***58] with the Board's conclusion that the record established clearly and convincingly that respondent was [*221] guilty of making knowingly false statements under oath in the Liberty/Ferber civil action and Client Security Fund proceeding. Our disagreement here results not from any clear error by the Board, but simply from our duty independently to scrutinize the record in disciplinary matters, as well as the inherent difficulty of proving false swearing charges.

As noted by the Board, respondent's June Twelfth letter to Waters' attorney outlining the committed funding sources was given to Ferber but not to Robertson, and respondent has stipulated "it was improbable" that Ferber
would forward the document to Robertson. However, at the 1982 trial respondent testified that he told Ferber to give the document, along with other materials, to Robertson, and that he assumed Ferber would do so. Further, although respondent stipulated that Ferber recognized Robertson would counsel against the deal and agreed "to take care of" him, respondent testified at the Client Security Fund hearing that he "had no idea that Mr. Ferber was not communicating the substance of our various discussions to ***59 his attorney."

We cannot conclude that this constitutes clear and convincing evidence that respondent knowingly lied under oath. The testimony related to respondent's recollection of his state of mind in 1979 regarding Ferber's state of mind concerning what Ferber might or might not do with a package of materials. The record indicates that Ferber and Robertson were in frequent contact during this period, and despite respondent's conceded knowledge that Ferber intended to keep Robertson somewhat at a distance, he may well have believed when testifying that the substance of their discussions was being relayed to Robertson, including the fact that Ferber had received the above-mentioned package of materials. Further, the transaction at issue was somewhat complex, involving multiple parties and a large number of relevant dates, events, and documents; yet some of the pertinent testimony was framed in terms of generalities and thus imprecise. Respondent's recognition today that it was unlikely Ferber would give the June Twelfth Waters' letter to [*222] Robertson, and that therefore his testimony was incorrect, does not ineluctably lead to the conclusion that he believed it was false ***60 when given. See N.J.S.A. 2C:28-2a (false swearing requires contemporaneous belief that testimony is false); State v. Boratta, 80 N.J. 506, 515 (1979) (same).

The other asserted incident of false testimony invoked by the Board, concerning respondent's role in the alteration of the Kaufman 1978 HLW financial statement, is not so easily explained. Respondent admits that he removed various pages from the statement and inserted a statement he prepared with a different net income figure, derived from a report compiled by his accountant using accrual-basis analysis. The alteration of this document was a topic of some concern at the 1982 trial, and came up at several points in respondent's testimony. Initially, respondent flatly denied he had altered the statement, but seemed to concede it had been tampered with prior to its submission to Liberty and the Weir Group:

Q. Referring you to S-39, there is a statement of income showing total net income of $524,132. Now, which of these two statements, the one showing $524,000 or the one showing $140,000, was the one you received from Mr. Tannenbaum?

A. What I received had the $140,000 in there, in some ***61 reference.

Q. Do you find $140,000 referred to it all on S-39, on the statement of income?

A. On this page.

Q. Yes, on that page.

A. On this page -- I don't know about the rest of the document this page -- it is not here. I don't see it on this page.

Q. Didn't you prepare this page, Mr. Silverman?

A. No.

THE COURT: Referring to a page in S-39?

Mr. SIMON: Yes.

A. I didn't prepare this page.

Q. Did you receive this page from Mr. Tannenbaum?

A. I think that that page came from some financial source. Whether it was Tannenbaum or whether it was Alper or Herman or who, but as a loose document, some time I saw this page.

Q. Well, so this page, this S-39 was not a part of the statement that you received from Mr. Tannenbaum, is that correct?

A. I don't believe so.

[*223] Yet at two subsequent points, once during cross-examination and once on redirect, respondent
denied having any knowledge of the alteration whatsoever.

Q. Did you ever see this document containing the $524,000 figure before this case started?

A. Before this case started?

Q. Yes.

A. No.

Q. Mr. Silverman did you ever change any financial information that was given to you [***62] by Mr. Tannenbaum?

A. No.

To be sure, this testimony was elicited from respondent in his capacity as a civil defendant, in the course of a complex trial spanning three weeks. Indeed, before the Ethics Committee respondent suggested that he was confused at trial when confronted with these documents. Primarily, however, respondent asserts that while testifying at trial he believed the inserted page had been "developed by Herman as part of his analysis," and thus when he denied preparing the inserted page himself, it was not knowingly false testimony:

At the trial I testified as I was best able to recall at that instant. I was asked a question about a subject that I had not seen nor heard or not thought about of for more than three years. So my response at trial in response to whatever was asked to me was not -- not wrong, not false; it's to my knowledge at that moment or instant of being questioned.

We find respondent’s explanation of the testimony not credible. His assertion that at the time he believed Herman had prepared the page is belied by his testimony during another point in cross-examination:

Q. [D]id you ask [Herman] or anyone else to take the figure [***63] shown on this letter and put them into -- and revise or change the Kaufman page on income?

A. I don't believe so.

Q. You don't believe so?

A. What I think, some of the consultants might have done was to make up, you know, their own notes.

Q. By consultants --

A. I don't know if it was Mastronardo or Alper. During this period those would have been the two that were closest to me.

[*224] Q. Did you talk to them about taking these figures that Herman had given you and making the revised statement of income?

A. No, because it would have been of no assistance because of what Liberty had already communicated.

Q. I'm not asking about Liberty; I'm asking --

A. The answer is no.

Q. -- about whether or not you asked anyone, Alper or Mastronardo or Herman, or anyone else, to take the figure shown on this June 1 '79 letter and put them into and develop a new income statement?

A. No.

Q. Do you know whether anyone did it on their own?

A. I don't know. [Emphasis added.]

Moreover, even if respondent did mistakenly believe at the time of trial that Herman had prepared the page and that he had only attached it to the Kaufman statement, he could not truthfully [***64] testify that he had never seen the altered document before the case started, and that he never changed any of the financial information given to him by Tannenbaum. See supra at 222. Hence,
on this matter we agree with the Board that respondent gave knowingly false testimony. See e.g., State v. Boratto, supra, 80 N.J. at 515 (witness' contemporaneous knowledge of falsity "may be inferred from surrounding circumstances," such as "the objective falsity itself, a motive to lie, or facts tending to show generally that defendant knew that his affirmation was false"); see also In re Reiss, supra, 101 N.J. at 491 (finding that attorney had filed knowingly false certification where he previously had represented the plaintiff in a different civil action but filed a certification denying he had ever represented the plaintiff in order to enable him to continue representing defendant).

We turn now to the appropriate discipline. Our primary objective is, as always, protection of the public and preservation of its confidence in the integrity of the bar, rather than punishment of the errant attorney. E.g., In re Stier, 108 N.J. 453, 460 (1987); Matter of Noonan, 102 N.J. at 165; In re Kushner, 101 N.J. 397, 400 (1986); In re Wilson, 81 N.J. 451, 456 (1979).

We examine the nature of the crime or misconduct and the extent to which it arises out of or relates to the practice of law, and consider pertinent evidence of mitigation. See [*225] Stier, supra, 108 N.J. at 457; In re Kotok, supra, 108 N.J. at 327; In re Kushner, supra, 101 N.J. at 400-01. Accordingly, our determination of the necessary sanction in disciplinary matters is "necessarily fact-sensitive." Id. at 400.

[**1245] We view respondent's misconduct in this case as most serious, as falling below not only the standards required of attorneys in their private commercial dealings but below general marketplace norms of fair dealing as well. Consumed with the prospect of owning HLW, respondent subverted basic tenets of honesty to his own personal and selfish interests. This dishonesty, coupled with respondent's breach of his obligation to warn Ferber of the need for independent counsel at the outset, [*66] resulted in a substantial loss to the Ferbers' estates. Respondent's knowingly false testimony, albeit given in the capacity of a litigant, nonetheless "is a fundamental breach of a lawyer's duty as an officer of the court * * * [striking at] the heart of every attorney's obligation to uphold and honor the law." In re Kushner, supra, 101 N.J. at 401 (quoting In re Schleimer, supra, 78 N.J. at 319 (1978)).

Several factors, however, counsel that we stay our hand short of disbarment. Unlike the continuing or multiple instances of fraud and deceit that warranted disbarment in In re Smyzer, supra, 108 N.J. 47, In re Servance, supra, 102 N.J. 286 and In re Bricker, 90 N.J. 6 (1982), respondent's fraudulent conduct was limited to a single transaction; apart from these events his record as an attorney is unblemished. See, e.g., In re Kushner, supra, 101 N.J. at 400 (evidence of "prior trustworthy professional conduct" may mitigate damage to integrity of bar); see also In re Schleimer, supra, 78 N.J. at 319 (noting relevance [***67] of substantially unblemished previous record); In re Hard, supra, 69 N.J. at 330 (same). Further, rather than counselling a client to invest in a losing commercial proposition in an attempt to protect the attorney's own interests, conduct we deem just short of misappropriation, e.g., In re Smyzer, supra, 108 N.J. at 57 (disbarred); In re Wolk, supra, 82 N.J. at 335 (same), respondent harbored a genuine belief that the [***226] venture would reap substantial rewards for both him and Ferber; indeed his inflated evaluation of HLW led him to burden the company's prospective cash flow beyond repair. 11 In sum, we are not inclined to view this as a case of an attorney "hoodwinking * * * clients out of funds in a business venture that is essentially for the benefit of the lawyer." Ibid.

11 Respondent's thinking in this regard is exemplified by the Board's revelation that in addition to the 25% interest the Weir Group was to receive on its $100,000 loan, respondent agreed at the closing "to pay the Weir Group $200,000 annually from HLW profits if the proposed [15%] partnership were not formed within four years * * * [and] to provide a principal of Weir with a 4-year 'consulting contract' worth $227,500, the proceeds of which were to inure to the benefit of the Weir Group." Supra at 204.

[***68] Our focus on the protection of the public and the preservation of its confidence in the bar renders significant the attenuated nature of the relationship between respondent's misconduct and the practice of law. See In re Stier, supra, 108 N.J. at 456-57 (where attorney filed false documents with registrar of deeds on behalf of clients court noted that infractions "arose from the lawyer-client relationship and were directly related to the practice of law"); In re Pleva, supra, 106 N.J. at 647 (where attorney was convicted of drug possession and falsification of firearm purchase application court noted that "misconduct was not directly related to the practice
of law"). Although Ferber and respondent related generally as attorney and client, and respondent failed in his responsibilities owed to Ferber as a client, supra at 213-217 (discussing DR 5-104(A), none of the misconduct arose out of practice-related powers or tasks. Compare In re Wilson, supra, 81 N.J. 451 (misappropriation of client trust funds). In this regard it is also significant to note that Ferber, who was not unconversant in dealing with attorneys, apparently voiced no complaints whatsoever concerning respondent's professional conduct before his death, eighteen months after the HLW closing.

Finally, the passage of time that has occurred since the relevant conduct mitigates the severity of the requisite discipline [*227] [**1246] in two respects. The most significant events at issue in this case occurred in the Winter and Spring of 1979, over nine years ago. Only last term in In re Kotok, supra, where nearly ten years separated the ethical infractions and finalization of discipline before this Court, we expressed that in such circumstances, the rehabilitation facet of the disciplinary process "has in some measure been accomplished through the passage of time." [*228] Disbarment or a further term of suspension may be unnecessary [***71] or even "counter productive," In re Kotok, supra, 108 N.J. at 331, and would likely smack of vindictiveness rather than justice. In re Verdiramo, supra, 96 N.J. at 187.

12 For example, with reference to DR 5-104(A) respondent testified that "I realize I made a grave mistake in my judgment, that Robertson should have been informed to the umpteenth degree. I should have refused to even meet with Ferber on anything but a social basis." Respondent acknowledged that much of what he did was absolutely wrong, and expressed that he had no desire to ever again attempt a role in a complex business transaction.

These related factors, and reference to our prior cases involving fraudulent conduct and false swearing, suggest that retroactive discipline is an appropriate choice of punishment in this case. See In re Simeone, 108 N.J. 515, 522-23 (1987) (serious and numerous infractions falling just short of knowing misappropriation; retroactive six year [***72] suspension); In re Kotok, supra, 108 N.J. at 330 (discussing propriety of retroactive discipline); In re Pauk, 107 N.J. 295, 302-06 (1987) (four-year retroactive suspension was sufficient discipline for five-year span of ethical transgressions involving "a pervasive pattern of neglect, misrepresentation, and overreaching"); In re Noonan, 102 N.J. at 165 (retroactive five-year suspension ordered for respondent guilty of nine instances of misconduct involving neglect of legal matters, failure to properly maintain books and records, and conduct adversely reflecting on fitness to practice); In re Kushner, supra, 101 N.J. at 402-403 (three-year retroactive suspension ordered for respondent convicted of false swearing as a civil litigant); In re Schleimer, supra, 78 N.J. at 319 (respondent convicted of false swearing as civil litigant given one-year suspension). We acknowledge that respondent's inexcusable lack of candor during the civil trial came three years after the primary misconduct at issue, and thus to some extent negates the suggestion that the latter was aberrational. [***73]
Nevertheless, based on our thorough scrutiny of the entire record, we are not convinced that the ethical violations in this case are of such a magnitude as to establish that respondent's professional career [*1247] must be terminated. Hence we decline to accept the recommendation of disbarment, and order instead that the six-plus years respondent has been suspended from practice in this State constitutes an appropriate discipline. Respondent is directed to reimburse the Ethics Financial Committee for appropriate administrative costs.

[*229] ORDER

This matter having been duly considered by the Court, it is ORDERED that the suspension of MELVIN SILVERMAN, formerly of CLIFTON, who was admitted to the bar of this State in 1970, from the practice of law by Order of the Supreme Court dated June 24, 1982, be deemed appropriate discipline for his violations of DR 1-102(A)(3), DR 1-102(A)(4), and DR 5-104(A); and it is further

ORDERED that respondent may seek to be restored to the practice of law pursuant to Rule 1:20-11(h); and it is further

ORDERED that MELVIN SILVERMAN reimburse the Ethics Financial Committee for appropriate administrative costs incurred in the prosecution [*74] of these proceedings.


Counsel: Gary J. Klein, with whom J. Cathy Vogel for New England Fuel Institute, Empire State Petroleum Association and Fuel Merchants Association of New Jersey, Robert C. Platt for Louisiana Association of Independent Producers and Royalty Owners, and Anne Marie Mueser for Anne Marie Mueser and GASP Coalition were on the joint brief, for petitioners in 91-1026, 91-1027, and 91-1028, and intervenors in 91-1081.


Jerome M. Feit, Solicitor, Federal Energy Regulatory Commission, with whom William S. Scheiman, General Counsel, Timm L. Abendroth and Randolph Lee Elliott, Attorneys, were on the brief, for respondent in 91-1026, 91-1027, 91-1028, 91-1081, and 91-1160.

Frederick M. Lowther, with whom Ernest B. Abbott, Frederic G. Berber, Jr., and Alan C. Geolot were on the joint brief, for intervenors, Iroquois Gas Transmission System, L.P. and Tennessee Gas Pipeline Company in 91-1026, 91-1027, 91-1028, 91-1081, and 91-1160. Johannes W. Williams and Carl M. Fink also entered appearances for intervenors.

J. Gordon Pennington and Daniel F. Collins entered appearances for intervenor, ANR Pipeline Company in 91-1026, 91-1027, 91-1028, 91-1081, and 91-1160.

Carl Ulrich, Stephen E. Williams, and Mark D. Calley entered appearances for intervenor, CNG Transmission Corporation in 91-1026, 91-1027, and 91-1028.


Barbara K. Heffernan and Bruce G. Glendening entered appearances for intervenors, Bay State Gas Company, et al. in 91-1026, 91-1027, 91-1028, and 91-1160.

Thomas F. Brosnan entered an appearance for intervenor, Granite State Gas Transmission, Inc. in 91-1027 and 91-1028.

John W. Ebert, Robert G. Hardy and Anthony J. Ivancovich entered appearances for intervenor, Transcontinental Gas Pipe Line Corp. in 91-1027 and 91-1028.

Steven J. Kalish, William I. Harkaway, Barbara M. Gunther and Donald Stanber entered appearances for
Paul W. Fox entered an appearance for intervenor, ProGas, Limited in 91-1081.

J. Richard Tiano entered an appearance for intervenor, The Southern Connecticut Gas Co. in 91-1160.


Per Curiam: [**4] The Iroquois/Tennessee Project is part of a billion dollar plan to ship natural gas from Alberta across the Canadian prairie to the Northeastern United States. Participants in the plan have sought licenses, certifications, and authorizations before numerous state, federal, and Canadian regulatory bodies. In this case, three groups of petitioners challenge the Federal Energy Regulatory Commission's certification of the American transportation component, a 370-mile pipeline extending from the Canadian border in upstate New York to Long Island. The first group consists of a coalition of upstate New Yorkers concerned about the environmental effects of the pipeline and fuel oil dealers from New England and Louisiana (the "Coalition"). They challenge the certification on the ground that the Commission reached its decision unfairly, improperly, and in violation of due process. The second group of petitioners are domestic oil and natural gas producers led by the State of Louisiana (the "domestic producers"). They argue that the Commission should have adjusted the rates of the proposed pipeline to compensate for what they allege to be the anticompetitive effects of Canadian rate designs. The [**5] final petitioner, the Texas Eastern Transmission Company, is one of the domestic pipelines involved in the project. It seeks review of FERC's refusal to grant it a case-specific certificate. Finding none of these petitions persuasive, we deny them.

OPINION BY: I THE IROQUOIS PIPELINE BEGINS IN IROQUOIS

OPINION

[*1107] I

The Iroquois pipeline begins in Iroquois, Ontario, and proceeds across the St. Lawrence River, eastern New York State, western Connecticut, and Long Island Sound, ending near South Commack, Long Island. The pipeline interconnects with a Canadian pipeline at its origin, with the Long Island Lighting Company's pipeline at its terminus, and with the Tennessee Gas Pipeline Company's system at two points along the way. To serve customers not directly linked to either the Iroquois or its own system, Tennessee plans to build some 140 miles of pipeline loops and laterals. The Tennessee system is connected to pipeline facilities operated by Algonquin Gas Transmission Company, which plans to build another 45 or so miles of loops and laterals to serve both customers importing gas from Canada and those shipping domestic gas through the ANR project. See infra p. 10.

To accommodate several New Jersey customers [**6] of the Iroquois/Tennessee Project, Texas Eastern plans to exchange domestic gas shipped on its pipeline for imported gas shipped on the Iroquois.

Once fully operational, the Iroquois/Tennessee Project will serve 17 local distribution companies (LDCs), three cogeneration customers, and one electric generation customer on a firm or continuous basis and provide interruptible service to an indeterminate number of other customers. Six of these LDCs, as well as Tennessee and Texas Eastern, have interests in the Iroquois Limited Partnership, the owner of the Iroquois pipeline. The other interests are held by domestic pipeline companies, the Power Authority of the State of New York, a Canadian natural gas supplier, and a Canadian pipeline.

The Commission's consideration of the Iroquois pipeline was, at least at first, unhurried. A group of LDCs, domestic pipelines, and a Canadian supplier first sought certification for the original Iroquois pipeline project - a 360-mile line serving 11 LDCs on a firm basis - in May of 1986. Rather than consider these applications, the Commission instituted an "open season" [*1108] on Northeast pipeline projects. Several years earlier, the Commission had considered [**7] a similar application for a pipeline that was part of a plan to ship natural gas from Alberta to the New York metropolitan region. Those proceedings became unwieldy because competitive proposals, necessitating comparative evidentiary hearings under Ashbacker Radio Corp. v. FCC, 326 U.S. 327, 90 L. Ed. 108, 66 S. Ct. 148 (1945), were filed throughout the deliberations, thereby rendering the original application "an administrative procedural moving target." Northeast U.S. Pipeline Projects, 40 F.E.R.C. 61,087, at 61,239 (1987). Determined to avoid these problems with the Iroquois application and to "act efficiently and expeditiously," the Commission announced on July 24,
1987, that anyone wishing a competitive evidentiary hearing on a project in the Northeast would have to file their application by December 1, 1987. Id. at 61,238. After extending the deadline to January 15, 1988, the Commission gathered the applications, divided them into different project proposals, and determined which of those proposals were competitive and therefore entitled to a comparative hearing. *Northeast U.S. Pipeline Projects, 42 F.E.R.C. 61,332, at 61,947 (1988).* [*8*] Thereafter, the applicants entered into settlement discussions; to encourage them, the Commission appointed a settlement judge. *Northeastern U.S. Pipeline Projects, 44 F.E.R.C. 61,150, at 61,431 (1988).*

After nearly a hundred conferences and meetings, the sponsors of the thirteen projects finally found to be competitive settled. They agreed to withdraw their various proposals and pursue three discrete joint projects: the ANR, the Champlain, and the Iroquois/Tennessee. *Northeast U.S. Pipeline Projects, 46 F.E.R.C. 61,012, at 61,063 (1989).* The ANR Project promised to increase access to domestic supplies by building a lateral from a pipeline in the Midwest to pipelines serving New England. The Champlain Project proposed to import gas from Quebec into New England via a 340-mile pipeline starting in Vermont at the Canadian border. The Iroquois/Tennessee Project largely tracked the original proposal for the Iroquois pipeline, modifying it slightly by extending the main pipeline some ten-odd miles and attaching various loops and laterals to it in order to serve more LDCs and to connect the Project with domestic pipelines in the Midwest. In accordance with the settlement, Iroquois, along with its new partners, Tennessee, Algonquin, and Texas Eastern, dismissed their pending applications and filed new ones constituting the Iroquois/Tennessee Project. When the Champlain project was abandoned, the Iroquois/Tennessee Project absorbed several additional LDCs.

Because its focus and purpose was procedural, the Northeast open season did not resolve any of the "public interest issues, including the firmness of supply and demand," relevant to the Project. Id. at 61,069. Nevertheless, consideration of these issues began well before the Iroquois/Tennessee Project applications were submitted. Under state law, the LDCs planning to purchase gas from Canada had to obtain approval from the relevant state regulatory agencies. Some of the hearings before these bodies were quite lengthy; the New York Public Service Commission proceedings lasted three years. There were also hearings before the Department of Energy's Fossil Energy office (DOE/FE), where the LDCs applied for import authorization, *Brooklyn Union Gas Co., 1 F.E. Par. 70,285 (1990),* and before Canada's National Energy Board for, among other [*10*] things, export authorization. Nor was the Commission entirely quiescent during the open season proceedings. In the spring and summer of 1988, it requested data from the LDCs on their expected demand for natural gas and held a technical conference on the general topic of demand in the Northeast. *Northeast U.S. Pipeline Projects, 44 F.E.R.C. at 61,427.* Six months earlier, the Commission had begun assembling data for its environmental impact statement.

Once the present applications were submitted, the level of activity before the Commission increased. The Commission repeatedly requested updated market data from the LDCs, until in the end there were [*1109*] eleven such requests, and it held another technical conference in November 1989. Parties also filed protests and comments, 142 in all, and on July 17, 1990, the Commission heard oral argument on the Project.

On July 30, 1990, the Commission issued a preliminary opinion. *Iroquois Gas Transmission Sys., 52 F.E.R.C. 61,091 (1990)* [hereinafter, "Preliminary Order"]. Despite the massive record before it, the Commission was not ready to rule on the Project. In the first place, it found Algonquin's application [*11*] incomplete because Algonquin had failed to specify which of its facilities would serve the Iroquois/Tennessee Project and which would serve the ANR Project. Accordingly, the Commission refused to consider Algonquin's application, and the parts of Tennessee's dependent upon it, until the application was complete.

By contrast, the Commission not only found the applications in what it termed Phase I of the Project complete; it determined that all disputed factual matters could be resolved based upon the written record. Nevertheless, over Commissioner Moler's dissent, the Commission chose not to issue a final ruling on Phase I. Instead, it announced that due to

the unprecedented level of public comment, input and concern which has been generated by these applications, and based upon the fact that the short delay associated with an expedited and narrowly focused hearing should not, in and of itself, adversely affect the
The Coalition petitioners assail the Commission's decision on a large number of essentially procedural grounds set forth in the margin.\footnote{The Coalition accuses the Commission of never seriously considering opposition to the Project. Instead, the Coalition asserts, the Commission conducted a sham certification proceeding in a sort of myopic determination to protect its "regulated constituency" and to "put pipe into the ground." These bold accusations are without foundation in the record. While the Coalition lists a number of instances of alleged unfairness, it}
suggests relatively few legal errors, none of which survives close attention.

The Coalition cannot, [**16] by sheer multiplication of innuendo, overcome the strong presumption of agency regularity. See, e.g., Withrow v. Larkin, 421 U.S. 35, 55, 43 L. Ed. 2d 712, 95 S. Ct. 1456 (1975); United States v. Morgan, 313 U.S. 409, 421, 85 L. Ed. 1429, 61 S. Ct. 999 (1941). Despite all their sound and fury, the attacks of the Coalition ultimately prove impotent.

The Coalition petitioners present the following "facts specifically relevant to procedural fairness":

- Under the guise of procedural housekeeping, [the Commission] ordered the appointment of a settlement judge to decide which, if any, of the competing project applications submitted in the "Open Season" were designed to serve discrete markets and therefore could avoid any comparative review.

- In implementing this assignment, the Chief ALJ, refusing to place ex parte conversations on the record, met only with pipeline advocates to devise a settlement, denying requests for discovery and hearing until subsequent proceedings.

- During March and April 1990, at least one Commissioner and various senior decision-making Commission staff conducted substantive ex parte meetings with senior executives of Iroquois owners and proponents.

- Although requests for discovery and hearing were initially made in July 1986, and renewed requests were made during the Open Season proceeding, and on the current application in February 1989 and thereafter, the Commission did not act upon any of these requests until July 30, 1990, following disclosures of ex parte meetings and a Senate hearing concerning the procedures and issues involved.

- The July 30 Order specifically limited discovery because of the expedited schedule - even though petitioners had never previously had access to information known only to Iroquois proponents.

- The July 30 Order denied [a] hearing on key issues of disputed material fact, including available alternatives to the project.

- The July 30 Order set forth the Commission's "Current Views on Issues Set for Expedited Hearing," thus giving its opinion on disputed issues of material fact prior to the hearing.

- The July 30 Order established these "current views" as the "starting point" for the hearing, and directed the parties to "challenge or support" the "current views," thus shifting the burden of proof and persuasion from Iroquois to the Petitioners.

- FERC presented no witnesses to support its current views, and refused to answer any data requests concerning its current views.

- The July 30 Order advised the ALJ that no hearing was needed, that there was already sufficient basis in the record to grant a certificate, and that a hearing was only being ordered for "public policy" purposes.

- The July 30 Order required completion of the entire fact finding process - pre-hearing conference, discovery, hearing, briefing and ALJ decision within 45 days - even though FERC could have acted on pending requests for hearings more than 18 months earlier and even though no emergency existed.

- In reliance on the July 30 Order, the ALJ denied Petitioners essential discovery and cross-examination, because of the expedition required, even though he recognized its relevance.

- Because of the shift in the burden of going forward and the expedition imposed, Petitioners were required to present their first witness only seven days after the prehearing conference, prior to hearing the case of Iroquois proponents or Commission staff, and without discovery on the impending direct case of the Iroquois proponents or the factual underpinnings of the Commission's "current views."

- The Iroquois witness presented, as the
principal basis of his testimony, a study prepared by Iroquois' 17 LDC shippers who were not present to testify and who could not be deposed because of lack of time. Discovery and cross-examination on assumptions made by the preparers of the only study on market needs and alternatives was denied.

A

The Coalition begins its litany of procedural complaints by accusing the Commission of engaging in ex parte meetings with Iroquois proponents during both the Northeast open season and the Iroquois/Tennessee certification proceedings. However, as both the Commission and Iroquois observe, the Coalition never actually argues that these meetings were improper or that they tainted the proceedings below.

As both the Commission and Iroquois observe, the Coalition does not actually argue that the rulings below should be set aside solely on the basis of these contacts. Instead, the Coalition appears to cite the ex parte contacts as evidence of procedural unfairness. Upon analysis, however, the record does not sustain the Coalition's charge. The only evidence in the record of the meetings is in the Northeast open season opinions and in a memorandum from the General Counsel detailing the information he "sought and . . . obtained from the Commission officials who participated" in meetings during the pendency of the Project application. Preliminary Order at 61,428. Although these sources confirm that there were informal communications between the Commission and parties to the proceeding below, including members of the Coalition, they also indicate that these discussions did not relate to the merits of the Project and that the petitioners suffered no prejudice from them.

- Because of the extraordinary expedition, Petitioners had one evening to prepare their cross-examination of the Iroquois witness and were required to present rebuttal testimony the day after the Iroquois witness completed his testimony.

- The Commission reaffirmed its "current views" based upon a finding that Petitioners' market projections [were not] "constructed on a forecast with more reasonable bases than those accepted by the Commission as its current view" without ever permitting examination of those current views.

Coalition Brief at 11-14 (footnotes & citations omitted).

2 After oral argument, the Coalition lodged with the court a report prepared by the General Accounting Office regarding the meetings covered by the General Counsel's memorandum. The Coalition has not requested a remand to the Commission for further evidentiary proceedings in light of the report. 15 U.S.C. § 717r(b). With respect to our review of the Commission's factual determinations, we cannot and do not consider the GAO report. We are limited to determining whether the Commission's findings are supported by substantial evidence contained in the administrative record. See, e.g., Edison Elec. Inst. v. OSHA, 849 F.2d 611, 623 n.16 (D.C. Cir. 1988); see also Association of Data Processing Serv. Orgs. v. Board of Governors of the Fed. Reserve Sys., 745 F.2d 677, 684 (D.C. Cir. 1984). The GAO report is not part of that record.

[**19] With respect to the Northeast open season proceedings, the ALJ did meet with Iroquois, Tennessee, and other competing applicants, but he did so in order to facilitate settlement. See supra p. 10. The Coalition was not part of those meetings for a simple reason: they had no competing [**1112] application to settle. Nor were there any "public interest" issues at stake in the open season. Northeast U.S. Pipeline Projects, 46 F.E.R.C. at 61,069. As mentioned above, the open season was a purely procedural device designed to avoid unnecessarily complicated competitive hearings. Neither of the two evils most commonly associated with ex parte contacts apply in such circumstances. By letting a judge supervise settlement agreements, parties do not engage in "surreptitious efforts to influence an official charged with the duty of deciding contested issues upon an open record in accord with basic principles of our jurisprudence." WKAT, Inc. v. FCC, 296 F.2d 375, 383 (D.C. Cir. 1961). In a settlement or in a purely procedural proceeding such as the open season, there are no issues to be decided "upon an open record in accord with basic principles of our jurisprudence." Similarly, because there is no judicial review of settlement negotiations, an ALJ's involvement in settlement negotiations cannot impede such review by creating "one administrative record for the public and this court and another for the Commission and those 'in the know.'" * Home Box Office, Inc. v. FCC, 185 App. D.C. 142, 567 F.2d 9, 54 (D.C. Cir.), cert.

The Coalition's complaints about the meetings in April and May of 1990 also are without support in the record. Although the meetings took place during the pendency of this proceeding, there is no evidence in the record, other than a single, quickly reproached comment, of any discussion going to the merits of the Project applications. The meetings focused instead upon the impact of cases pending at that time before this court, upon general problems in the industry, and upon the procedural status of the Iroquois application. Such discussions are not prohibited by the mere fact an application is pending. The Administrative Procedure Act bars ex parte communications only if they are "relevant to the merits of the proceeding." 5 U.S.C. § 557(d)(1)(A). Other communications, including [**21] inquiries into the procedural status of the case or general background discussions, are not prohibited. See, e.g., Professional Air Traffic Controllers Org. v. FLRA, 222 App. D.C. 97, 685 F.2d 547, 563 (D.C. Cir. 1982).

Moreover, acting upon the chance that the industry representatives were attempting subtly and indirectly to influence the outcome of this proceeding, 3 the Commission wisely placed summaries of these meetings in record. By doing so, it apprised the petitioners of any discussion going to the merits of the Project. Other communications, including [**21] inquiries into the procedural status of the case or general background discussions, are not prohibited. See, e.g., Professional Air Traffic Controllers Org. v. FLRA, 222 App. D.C. 97, 685 F.2d 547, 563 (D.C. Cir. 1982).

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3 Representatives from the LDCs noted a cold snap the previous December, discussed the general supply-and-demand picture for the Northeast, and urged that Iroquois' application be processed in a timely or expedited manner. Considering all these factors together, one might infer a circuitous attempt to impress upon the Commission the urgency of approving the Iroquois/Tennessee Project. It is, however, important to note that none of the factors mentioned by the representatives were news to the Commission. Moreover, in public letters to the Commission during the same time period, the industry representatives presented a more complete and direct argument for expedited consideration and approval.

[**22] By the same token, the Commissioners involved in those meetings properly refused to disqualify themselves due to these contacts. Because the record reveals at best subtle and indirect attempts to influence Commission officials, no disinterested observer would infer that those officials had in any measure prejudged the applications. Cinderella Career & Finishing Schools v. FTC, 138 App. D.C. 152, 425 F.2d 583, 591 (D.C. Cir. 1970). It is expected that administrative officials will build up expertise through experience with recurring issues. FTC v. Cement Inst., 333 U.S. 683, 702 (1948). Such expertise should not lightly be tossed aside. Cf. Laird v. Tatum, 409 U.S. 824, 837, 34 L. Ed. 2d 50, 93 S. Ct. 7 (1972) (memorandum by Justice Rehnquist).

[**1113] In short, while there were meetings between agency officials and Iroquois and other industry officials, the record supports the Commission's conclusion that there was nothing improper about those meetings. Agency officials may meet with members of the industry both to facilitate settlement and to maintain the agency's knowledge of the industry it regulates. As this court has noted before, "such informal contacts between agencies and [**23] the public are the 'bread and butter' of the process of administration and are completely appropriate so long as they do not frustrate judicial review or raise serious questions of fairness." HBO v. FCC, 567 F.2d at 57. Because we find no evidence in the record indicating that judicial review has been frustrated or that any serious questions of fairness have been presented, we sustain the Commission's finding that "the integrity of the decisionmaking process has been fully maintained." Order No. 357 at 61,719.

B

The Coalition petitioners support their other grievances with legal argument. Their primary claim is based upon due process. Focusing upon the August hearing, the Coalition contends that it was prevented from conducting either discovery or cross-examination upon the assumptions underlying the evidence submitted by Project supporters and relied upon by the Commission. As a consequence, the Coalition asserts, it was precluded from criticizing that evidence and, therefore, from effectively contesting Iroquois' application. The Commission's response is simple and compelling: even without the August hearings, the
Coalition had all the process it was due.

According [**24] to the Commission, due process did not require the August hearing or indeed any additional proceedings. Opponents of the Project had ample opportunity to oppose the Project in written submissions and oral argument. In the Commission’s view, the only thing they lacked was a trial-type evidentiary hearing, but, given the nature of the facts in dispute, there was no need for such a hearing. Trial-type proceedings, the Commission reasoned, are necessary only when “a witness’ motive, intent, or credibility needs to be considered” or “where the issue involves a dispute over a past occurrence.” Preliminary Order at 61,368.

That was not the situation here. The Coalition and the sponsors of the Iroquois/Tennessee Project primarily dispute whether additional pipeline capacity is needed to meet future demand, a “purely technical issue” capable of being resolved not on the basis of a witness’ motive or memory, but rather upon an “analysis of the conflicting data and a reasoned judgment as to what the data shows.” Id. at 61,369; see also Order No. 357A at 61,346; Order No. 357 at 61,685. Because the Coalition petitioners had an adequate opportunity to present their case without the August [**25] hearing, the Commission concluded that due process was not violated by the abbreviated nature of that proceeding. Order No. 357 at 61,689.

The Coalition petitioners offer no real answer to this argument. Indeed, they concede that written submissions and documentary evidence should have been sufficient to resolve their factual disputes with the Project sponsors. Coalition Brief at 16, 25. They do suggest that even before the August hearing they were denied a meaningful opportunity to test, criticize, and illuminate alleged flaws in the evidence submitted by Iroquois. See, e.g., Morgan v. United States, 304 U.S. 1, 18, 82 L. Ed. 1129, 58 S. Ct. 773, 58 S. Ct. 999 (1938); ICC v. Louisville & N.R.R., 227 U.S. 88, 93-94, 57 L. Ed. 431, 33 S. Ct. 185 (1913). This, however, is belied by the record. The Coalition had adequate notice of the Iroquois/Tennessee applications, all of which were published in the Federal Register. [*1114] Preliminary Order at 61,534. They also had access to, and ample time to analyze, all the evidence of market need submitted by Iroquois and the LDCs planning to ship on the pipeline. Indeed, that evidence was available even before the Iroquois/Tennessee applications were submitted. Much of it had been [**26] introduced in other proceedings, including those before New York Public Service Commission, which were made part of the record in this case. Additional evidence was elicited during two public technical conferences, one held in connection with the Northeast open season and the other with the present application, and in response to the eleven data requests issued to Iroquois and the LDCs. See supra p. 11.

4 Because of this concession, we express no opinion on whether Boston Carrier, Inc. v. ICC, 234 App. D.C. 274, 728 F.2d 1508, 1511 n.5 (D.C. Cir. 1984), can or should be extended to cover certification proceedings under the Natural Gas Act. Nor need we consider whether the proceedings below were a formal adjudication under the Administrative Procedure Act entitling opponents of the Project to cross-examination. 5 U.S.C. § 556(d).

The Coalition petitioners also had sufficient opportunity to criticize the evidence submitted by Iroquois and the LDCs. Indeed, they assert that they submitted “substantial and specific [**27] factual predicates” contradicting that evidence. Coalition Brief at 24. Those “predicates” include several studies specially commissioned for the proceedings below (J.A. 464 (Technical Associates, Incorporated)); id. at 564-628 (USI Incorporated)), general studies by governmental and industry bodies (Preliminary Order at 61,379 (Energy Information Administration)); J.A. 481 n.2 (North American Electric Reliability Council); id. at 570 (Gas Research Institute)), and calculations based upon the market projections submitted by the LDCs (id. at 440, 454-63, 570-71, 676-78). Not surprisingly, members of the Coalition also availed themselves of the opportunity to criticize thoroughly the manner in which Iroquois and other Project proponents analyzed those projections. See, e.g., id. at 431-32, 450-51, 496-97, 570, 632, 773-83.

In addition to receiving notice of the evidence upon which Iroquois relied, an opportunity to review it, and a chance to submit briefs criticizing it and evidence contradicting it, the Coalition was also able on July 17, 1990, to argue before the Commission. Given all these opportunities to present its case, the Coalition’s assertion that it was denied [**28] a meaningful opportunity to be heard is unfounded.

Undaunted, petitioners maintain that these opportunities were illusory because they did not know the critical facts upon which the Commission relied. Specifically, the Coalition contends that it was unable to
Defense Council, Inc., the contention that it was denied due process must therefore be rejected. 6 Once due process is satisfied the amount and form of any additional process an agency wishes to provide is left almost entirely to its discretion. Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc., 435 U.S. 519, 543-44, 55 L. Ed. 2d 460, 98 S. Ct. 1197 (1978). 1A. These petitioners may have desired a greater opportunity to present their case than the limited nature of the August hearings provided, or to their lack of opportunity to test, criticize, and illuminate [**29] the flaws in that evidence. See infra p. 25.

Once it is established that even before the August hearing the Commission provided the Coalition with all the process it was due, the Coalition's other criticisms of the hearing are easily dismissed. Due process is sufficiently flexible to permit consideration of the August hearing in light of the proceedings that went before. See, e.g., Morrissey v. Brewer, 408 U.S. 471, 481, 33 L. Ed. 2d 484, 92 S. Ct. 2593 (1972); Cafeteria & Restaurant Workers Union v. McElroy, 367 U.S. 886, 895, 6 L. Ed. 2d 1230, 81 S. Ct. 1743 (1961). Since the Coalition petitioners had a meaningful opportunity to meet Iroquois' contentions before the August hearings, they can hardly argue that those supplemental hearings, no matter how expedited or limited, denied them such an opportunity. 5 Although [*1115] these petitioners may have desired a greater opportunity to present their case than the limited nature of the August hearing provided, once due process is satisfied the amount and form of any additional process an agency wishes to provide is left almost entirely to its discretion. See generally Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc., 435 U.S. 519, 543-44, 55 L. Ed. 2d 460, 98 S. Ct. 1197 (1978). [**30] The Coalition's contention that it was denied due process must therefore be rejected. 6

5 This is not to say that absent the prior proceedings the Coalition's criticisms of the August hearing would be valid. For example, their request to cross-examine Commission staff on the basis of their market need analysis was plainly improper; parties have no right to inquire into an agency's mental processes. United States v. Morgan, 304 U.S. at 18; De Cambra v. Rogers, 189 U.S. 119, 122, 47 L. Ed. 734, 23 S. Ct. 519 (1903).

6 The Coalition petitioners also assert that the Commission shifted the burden of proof onto them by setting forth its "current views" on the evidence and instructing the ALJ to take those views as his starting point in the August hearing. It is true that by noting that the evidence currently in the record favored the applicants, the Commission informed petitioners that they would have to produce additional evidence in order to make their case. However, the ultimate burden of persuasion remained with the applicants, Order No. 357A at 61,349-50; Order No. 357 at 61,690. The Commission's instructions were designed to benefit petitioners, "to focus the hearings and to give the parties a meaningful opportunity to challenge or support [the Commissions current] views." Id.

We express no view on whether due process would be violated by a supplemental hearing that was a mere sham. The Coalition contends that the Commission's instructions to the ALJ predetermined his judgment. But the Coalition has failed to present any basis for supposing that the ALJ "heard the testimony with a deaf ear and a closed mind." NLRB v. Donnelly Garment Co., 330 U.S. 219, 229, 91 L. Ed. 854, 67 S. Ct. 756 (1947).

Finally, the Coalition argues that, by requiring the ALJ to start from the Commission's current views, the Commission forced the ALJ to prejudge the issues before him. In considering the evidence already in the record and the Commission's initial assessment of that evidence, the ALJ was in the same position as an ALJ, after reversal and remand, reconsidering a case (Donnelly Garment Co., 330 U.S. 236 at 236-37). There is no reason here to think the ALJ's mind was closed to the evidence subsequently added to the record and, consequently, no showing that due process was violated.

[**31] C

Reformulating the same basic complaints, the
Coalition asserts that because it did not have an adequate opportunity to criticize the evidence submitted by Project proponents, the Commission's findings were not supported by substantial evidence as required by the Natural Gas Act. Natural Gas Act § 19(b), 15 U.S.C. § 717r(b). Under the substantial evidence test, the evidence relied upon by the agency must be substantial in light of the whole record. Universal Camera Corp. v. NLRB, 340 U.S. 474, 488, 95 L. Ed. 456, 71 S. Ct. 456 (1951); Association of Data Processing Serv. Orgs. v. Board of Governors of the Fed. Reserve Sys., 745 F.2d 681 at 681-86. A corollary to the "the rule that the 'whole record' be considered" is that interested parties must have an opportunity "to introduce adverse evidence and criticize evidence introduced by others." Mobil Oil Corp. v. FPC, 157 App. D.C. 235, 483 F.2d 1238, 1258 (D.C. Cir. 1973) (emphasis omitted); see also Wisconsin Gas Co. v. FERC, 248 App. D.C. 231, 770 F.2d 1144, 1167-68 & n.38 (D.C. Cir. 1985) (limiting Mobil Oil on other grounds), cert. denied, 476 U.S. 1114 (1986). The Coalition petitioners contend that [**32] by denying them access to the assumptions underlying the LDCs' market data the Commission prevented the record from being sufficiently developed to support its conclusion. However, as discussed previously, petitioners did have access to the assumptions underlying the LDC projections. Furthermore, the Commission's conclusions were supported by the evidence in the record.

There was ample record evidence suggesting a need for the Iroquois/Tennessee Project. As mentioned before, each of the LDCs planning to ship natural gas on the Iroquois pipeline submitted market growth projections to the Commission indicating the need for at least as much capacity as the pipeline promised. Preliminary Order at 61,378. These projections fit comfortably [*1116] within the range of projections made in more general regional forecasts. Id. at 61,380 & n.108. The predicted growth rates were also consistent with historical data, with current evidence of supply deficiencies, and with the actual growth rate for 1989-90. Id. at 61,382; Order No. 357 at 61,695-96. Furthermore, the LDCs were willing to back up their analysis with action by entering into long-term sales and transportation agreements in connection [**33] with the Project, Preliminary Order at 61,382, and the state agencies charged with regulating them, after much scrutiny, approved those agreements. Id. at 61,382 n.116.

In response to this evidence, the Coalition and other opponents of the Project submitted their own evidence and evaluations, all of which the Commission considered and rejected. Petitioners criticized the conclusions drawn from the LDC projections. While conceding that the overall projected growth rates were reasonable, opponents of the Project claimed that there was an unreasonably large "growth spike" between 1989-90 and 1991-92 in the LDC projections. The Commission dismissed this assertion because it was, for the most part, "derived from inaccurate comparisons of data." Order No. 357 at 61,695. The opponents had compared unadjusted historical and current data to projections adjusted for different weather conditions and for quantities of gas lost. Id. Moreover, the opponents' data did not consider the projected jumps in demand that would occur when new electric generation and cogeneration plants come on line. Id. at 61,695-96. The Commission rejected as well criticism of the historical growth data submitted [**34] by Project supporters. Because that data covered the period from 1978-89, opponents claimed that it overstated growth rates by measuring from the depths of a recession. The Commission found that despite this problem the data remains useful because it paralleled the eleven-year period being considered in connection with the Project and contains "a great number of data observations, including periods of curtailment and surplus, periods of high and low oil prices, and periods of economic upturns and downturns." Id. (footnote omitted). More fundamentally, the Commission found that any distortion caused by the recession in 1978 would not affect the LDC projections because those projections are not extrapolated from historical data. Id. Finally, the Commission rejected the criticism that the LDC projections had been submitted in 1988 before the current economic downturn on the ground that those projections had been recently updated. Id. at 61,698.

As to the evidence submitted by opponents of the Project, the Commission observed that one study actually supported the LDCs' contention that additional supplies were necessary to meet peak demands. Preliminary Order at 61,379. The [**35] Commission also found flaws in the opponents' recalculation of the LDCs' data. These calculations, the Commission found, improperly focused upon peak months. As a consequence, the opponents' calculations neither indicated whether the current system could handle "needle peaks on certain cold days" nor reflected the way that LDCs plan their requirements. Id. at 61,381. In addition, these calculations were, in the
Commission's opinion, based upon faulty premises. They ignored the desired and expected increase in electrical generation and cogeneration loads, the desirability of reliable service, and the public's interest in promoting competition among energy supplies and reducing dependence upon imported oil. *Id. at 61,380*; Order No. 357 at 61,695.

Finally, the Commission addressed the argument that "peak shaving facilities" that inject liquid natural gas and other fuels into natural gas pipelines could be relied upon to relieve any peak day deficiencies. It found the evidence submitted by Project opponents to be flawed on several grounds: among other things, the evidence assumed the use of facilities that had already been decommissioned, ignored concerns over the reliability of peak shaving supplies, and failed to consider technical limitations upon the amount of such supplies that could be used at once. *Id.* at 61,697.

[*1117] In sum, the Commission thoroughly canvassed the evidence both for and against Iroquois' proposed pipeline and properly found a need for it. The Coalition's substantial evidence challenge must therefore be rejected.

D

Alternatively, the Coalition claims that the Commission violated the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. §§ 4321-4370c, by failing to consider alternatives to shipping the Northeast natural gas from the Pacific Coast of Canada. 7 Section 102(2)(C) of NEPA requires every proposal for major Federal action to include "a detailed statement by the responsible official on ... the environmental impact of the proposed action ... [and] alternatives to the proposed action ... ." 42 U.S.C. § 4332(2)(C). Because this requirement is "essentially procedural," in reviewing an agency's compliance with it courts need only "ensure that the statement contains sufficient discussion of the relevant issues and opposing viewpoints to enable the decisionmaker to take a 'hard look' at environmental factors, [*37] and to make a reasoned decision." Natural Resources Defense Council, Inc. v. Hodel, 275 App. D.C. 69, 865 F.2d 288, 295 (D.C. Cir. 1988) (quotations omitted). The Commission's statement easily satisfies this standard. The final environmental impact statement discusses the major options to the Iroquois/Tennessee Project, and the draft environmental impact statement devotes a whole volume, totalling several hundred pages, to the options before the Commission. Petitioners nevertheless criticize the final statement for failing to consider properly such options as using existing pipeline capacity, more "peak shaving," and conservation. However, the final statement does consider these choices. The statement questions reliance upon existing pipeline capacity on the ground that there are already capacity constraints during peak demand periods, finds the potential for conservation limited due to "existing technological, institutional, political, and social barriers," and expresses doubts about expanded use of peak shaving facilities because such facilities are neither cost-competitive nor efficient. *Id.* 700-01, 703-05. The Commission also considered using a combination of these three options. *[*38] Id. at 711-13.* We therefore find that the Commission's environmental impact statement fulfilled NEPA's purpose of ensuring a "fully informed and well-considered decision." Vermont Yankee v. Natural Resources Defense Council, Inc., 435 U.S. at 558.

7 The Coalition petitioners also contend that the final environmental impact statement improperly failed to consider the need for the Iroquois/Tennessee Project. This is only partially correct. While the ultimate determination of that issue was left to the Commission to resolve in its order, the final statement does contain a brief description of the need. *Id.* 699. The regulations promulgated by the Council on Environmental Quality authorize agencies to avoid unnecessary duplication in just this manner. 40 C.F.R. § 1506.4.

E

In addition to questioning the manner in which the Commission conducted private meetings, the manner in which it conducted public hearings, the manner in which it discussed options, and the manner in which it analyzed the evidence [*39] before it, the Coalition petitioners also criticize the manner in which the Commission applied its own policies. 8

8 Noting several flaws in Project applications, see, e.g., supra pp. 11-12, the Coalition also contends that the Commission should have rejected them altogether pursuant to a regulation requiring applicants to "file all pertinent data and information necessary for a full and complete understanding of the proposed project." 18 C.F.R.
§ 157.3(a). We need not consider whether these contentions have any support in Commission regulations or policy. Because allegations of these errors were raised for the first time upon appeal, we lack jurisdiction over them. Natural Gas Act § 19(b), 15 U.S.C. § 717r(b). The Coalition’s brief also offers several challenges in the name of Dr. Joyce Brothers concerning the proposed routing of the Iroquois pipeline near her house in upstate New York. Because Dr. Brothers has withdrawn these challenges, we do not consider them.

1. In its original application for the Project, [**40] Iroquois proposed to construct a lateral from its main pipeline to provide [*1118] service directly to two LDCs, Connecticut Natural Service and Yankee Gas Services. During the Open Season settlement, Iroquois and Tennessee agreed that it would be more efficient for Tennessee to provide the same service. As part of that agreement, Iroquois proposed to pay for the transportation over Tennessee’s pipeline. As a result, unlike other shippers on Iroquois who must pay all the costs of using the Tennessee system, Connecticut Natural and Yankee Gas would pay only a small percentage of the cost of their use of the Tennessee, with the rest paid for by the other Iroquois shippers. Despite this cross-subsidization, the Commission approved the proposed rates because it was "reluctant to interfere with the parties’ settlement of this issue when no customer allegedly disadvantaged by the relationship has complained." Order No. 357A at 61,360.

The Coalition petitioners charge that by doing so the Commission acquiesced in a discriminatory rate. The Natural Gas Act only prohibits "undue preferences" and "unreasonable differences in rates." Natural Gas Act § 4(b), 15 U.S.C. § 717c(b). Observing the importance [**41] the Supreme Court has placed upon preserving private contractual arrangements (United Gas Pipe Line Co. v. Mobile Gas Serv. Corp., 350 U.S. 332, 100 L. Ed. 373, 76 S. Ct. 373 (1956); FPC v. Sierra Pac. Power Co., 350 U.S. 348, 100 L. Ed. 388, 76 S. Ct. 368 (1956)), this court has upon several occasions noted that settlement agreements can justify a rate differential. United Mun. Distribs. Group v. FERC, 732 F.2d 3202, 212 (D.C. Cir. 1984); City of Bethany v. FERC, 727 F.2d 1131, 1139 (D.C. Cir.), cert. denied, 469 U.S. 917 (1984); Borough of Chambersburg v. FERC, 580 F.2d 573, 577 (D.C. Cir. 1978) (per curiam). To qualify, the agreements must have been negotiated in good faith and must not unduly burden any group of customers. United Mun. Distribs. Group v. FERC, 732 F.2d at 212; City of Bethany v. FERC, 737 F.2d at 1139-40. Since the Commission had no evidence before it suggesting the settlement agreements were either the product of improper conduct or placed an undue burden upon any customers, its determination that there was no undue discrimination is supported by substantial evidence [**42] and must therefore be upheld. Natural Gas Act § 19(b), 15 U.S.C. § 717r(b).

2. The Coalition petitioners also contend that the Commission departed from its policy of setting a single depreciation rate for each pipeline system. In particular, although Tennessee’s normal depreciation rate is 2.5 percent, the Commission approved a 5 percent annual rate of depreciation for certain pipeline loops built in connection with the main Iroquois pipeline. Order No. 357A at 61,364. There is nothing to the argument. The Commission has in the past authorized different depreciation rates for lateral pipelines devoted entirely to a single power plant on the ground that the depreciation rate of the lateral line should be the same as the rate for the power plant. Tennessee Gas Pipeline Co., 45 F.E.R.C. 61,010, at 61,044-45 (1988). Here, the Commission found that because "the new Tennessee facilities are located downstream of a capacity bottleneck, which makes it unlikely the facilities could provide service to other customers," those facilities are "almost wholly limited to serving Iroquois shippers" and "dependent upon Iroquois’ facilities." Order No. 357A at 61,364. Based [**43] upon these facts, the Commission reasonably concluded that the depreciation rate for the new Tennessee facilities should reflect the expected life of the Iroquois pipeline, not of the Tennessee system as a whole, and approved an annual depreciation rate of 5 percent, the rate for the Iroquois system. Id. Thus, contrary to the Coalition petitioners’ contention, the Commission followed rather than departed from agency precedent in granting Tennessee a special depreciation rate for facilities constructed in connection with the Project.

F

Finally, the Coalition petitioners directly attack the fairness of the Commission. Without citation to the record, [*1119] they charge Chairman Allday with saying at a meeting after the August hearing something to the effect that his job was to "put the pipe in the ground." Coalition Brief at 8. We are not sure what to make of this.
We do not know what Chairman Allday said. For its part, the Commission described his statements as "expressing a general interest in expediting the regulation process." Opinion No. 357A at 61,355. It would take considerably more than the unsupported allegation in a brief to show that the Commission or any one of its members failed [*44] to act impartially. Under the well-settled presumption of administrative regularity, courts assume administrative officials "to be men [and women] of conscience and intellectual discipline, capable of judging a particular controversy fairly on the basis of its own circumstances." Withrow v. Larkin, 421 U.S. at 55 (quoting United States v. Morgan, 313 U.S. at 421).

Although that presumption can be rebutted, the evidence submitted must be far more compelling than a pattern of adverse but nonetheless justified discretionary decisions. See, e.g., Association of Nat'l Advertisers, Inc. v. FTC, 201 App. D.C. 165, 627 F.2d 1151, 1170 (D.C. Cir. 1979), cert. denied, 447 U.S. 721 (1980).

III

In a second petition for review, the State of Louisiana and the Louisiana Association of Independent Producers and Royalty Owners (LAIPRO), together with several domestic oil and gas producers (who join petitioners' brief as intervenors), challenge the Commission's decision not to adjust Iroquois' transportation rates to offset the alleged competitive advantage that will otherwise accrue to the Canadian gas carried on the pipeline because of [*45] differences between Canadian and domestic rate design policies. Firm transportation rates in both Canada and the United States consist of two parts, a fixed monthly "demand" charge and an avoidable "commodity" charge imposed only on gas actually transported. Regulators in each country, however, use different methodologies to allocate costs between the two charges: Canada's "fixed-variable" method allows pipelines to recover most of their fixed costs associated with transportation in the demand charge, while under FERC's "modified-fixed-variable" method domestic pipelines recover a large portion of their fixed costs through the commodity charge. According to petitioners, the resulting "rate tilt" (higher demand and lower commodity charges on Canadian gas) will give the imported gas carried on the Iroquois pipeline an unfair competitive advantage over domestic gas supplies.

In the proceedings below, the domestic producers urged the Commission to adjust Iroquois' rates to compensate for this alleged anticompetitive effect. They relied upon FERC's Order No. 256, Natural Gas Pipeline Co., 37 F.E.R.C. 61,215 (1986), to support their proposition that domestic producers [*46] should not be disadvantaged by the interaction of domestic and Canadian rate structures. In Order No. 256, a pipeline that purchased and resold Canadian gas sought to pass through the costs of the gas to domestic buyers as-billed (that is, using the fixed-variable methodology); FERC disallowed the request and reallocated the costs in the resale agreements between the demand and commodity components to bring the rates in compliance with domestic policy. Arguing by analogy, the domestic producers in this case proposed a number of solutions to the alleged "rate tilt," in this case, all of which involved artificially increasing Iroquois' commodity charge. In Order No. 357, the Commission rejected these proposals, citing its policy against attempting to equalize all rate differentials between competing pipelines and concluding that it could not make an exception consistently with its obligations under the Canada-United States Free Trade Agreement, 27 I.L.M. 281 (1988) (Free Trade Agreement), without entering a regulatory morass. We are of the view that the Commission's reasoning adequately supports its decision not to adjust Iroquois' rates and therefore deny the petition [*47] for review on the "rate tilt" issue.

the Secretary of Energy responsible for regulating the importation of natural gas pursuant to section 3, 15 U.S.C. § 717b, see 42 U.S.C. § 7172 (transferring Federal Power Commission functions to FERC and omitting section 3 powers); id. § 7151(b) (vesting in the Secretary of Energy functions not transferred to FERC). In 1984 the Secretary of Energy delegated authority to administer section 3 to the Economic Regulatory Administration (ERA), see Delegation Order No. 0204-111, 49 FR 6690 (1984), and at the same time delegated to the Commission all functions related to imports under section 7, see Delegation Order No. 0204-112, id. Recently, the ERA's responsibility was transferred to DOE/FE. 9 See Delegation Order No. 0204-127, 54 FR 11,436 (1989).

9 We will refer to ERA as DOE/FE throughout this opinion.

Section 3 of the NGA provides that authorization for proposed natural gas imports shall issue if the imports are "consistent with [***49] the public interest." 15 U.S.C. § 717b. The Policy Guidelines accompanying the 1984 delegation orders instruct DOE/FE, when deciding whether a proposed import is consistent with the public interest, to consider the competitiveness of the import, the need for the gas, and the security of the supply. And DOE/FE, when it focuses on the competitiveness question, must consider whether the terms of the import arrangement taken as a whole will provide a supply of gas that will market competitively and whether the terms of the contract are sufficiently flexible to ensure competitiveness throughout the contract's duration. See New Policy Guidelines and Delegation Orders from Secretary of Energy to Economic Regulatory Administration and Federal Energy Regulatory Commission Relating to the Regulation of Imported Natural Gas, 49 FR 6684, 6687-88 (1984) (Policy Guidelines).

In this case, DOE/FE determined that the Canadian gas to be carried over the Iroquois pipeline would market competitively and that the import agreements were sufficiently flexible so that the gas would remain competitive. 10

See Brooklyn Union Gas Co., 1 F.E. Par. 70,285, at 71,211 (1990). [***50] It also addressed the "rate tilt" issue because the domestic producers raised that matter before it. The producers requested that DOE/FE correct for the alleged anticompetitive effect either by requiring the border price to be adjusted every six months to ensure that the demand component contained nothing that FERC would not allow domestic pipelines to recover through the demand component, or by making the import authorization contingent upon FERC's approving fixed-variable [***121] rates for domestic pipelines generally. See id. at 71,205.

10 The agency first made preliminary conclusions regarding the competitiveness of the proposed imports and conditioned authorization on completion of a DOE review of the environmental impacts of the Iroquois project. See Brooklyn Union Gas Co., 1 F.E. Par. 70,285, at 71,218-19 (1990). Upon completion of the environmental review, DOE/FE authorized the import agreements in an opinion that adopted the agency's prior competitiveness findings. See Brooklyn Union Gas Co., 1 F.E. Par. 70,370, at 71,419-20 (1990). Rehearing was subsequently denied. See Brooklyn Union Gas Co., 1 F.E. Par. 70,400 (1991).

[***51] DOE/FE determined that the domestic producers had failed to demonstrate that the alleged "rate tilt" rendered the import contracts as a whole uncompetitive. See id. at 71,212-13. It emphasized that parties opposing import contracts must overcome the presumption that "buyers and sellers of natural gas will construct competitive import arrangements that will be responsive to market forces over time," id. at 71,211, and that the Policy Guidelines disfavor unilateral alterations of freely negotiated agreements, see id. at 71,212. The agency pointed out that it (and federal courts) had previously authorized similar import contracts, including a virtually identical arrangement in Boundary Gas, Inc., 1 E.R.A. Par. 70,539 (1983), and it noted that the domestic producers had presented no evidence that the gas in that case "enjoyed an unfair competitive advantage over domestic supplies." Brooklyn Union, 1 F.E. at 71,205. DOE/FE recognized, however, that in a 1989 policy statement FERC "indicated a willingness to reconsider the modified-fixed variable rate in order to promote economic efficiency in natural gas markets" and stated [***52] that FERC "appears to be considering [opponents'] concerns." Id. at 71,216 (referring to Interstate Natural Gas Pipeline Rate Design, 47 F.E.R.C. Par. 61,295 (1989)). It said that "the DOE supports FERC's efforts to develop rate methodologies which will enhance efficiency and further the goal of competitive gas markets." Id. Because of the Commission's generic
"ongoing review of pipeline rate design," DOE/FE concluded that it would be inappropriate for DOE/FE to adopt opponents' proposed conditions for this particular import arrangement. Id.

When the "rate tilt" issue was subsequently raised in section 7 proceedings before FERC, the Commission suggested in its Preliminary Order that it lacked jurisdiction to redress the alleged problem because DOE/FE had already considered the issue (which, in light of DOE/FE's deference to FERC, sounds a bit like the Alphouse-Gaston act.). Under section 7, FERC may grant a certificate authorizing the transportation of imported gas if the proposed transportation "is or will be required by the present or future public convenience and necessity." 15 U.S.C. § 717(f). Before issuing the certificate, it must [**53]"evaluate all factors bearing on the public interest." FPC v. Transcontinental Gas Pipe Line Corp., 365 U.S. 1, 8, 5 L. Ed. 2d 377, 81 S. Ct. 435 (1961) (Transco) (quoting Atlantic Refining Co. v. Public Serv. Comm'n, 360 U.S. 378, 391, 3 L. Ed. 2d 1312, 79 S. Ct. 1246 (1959)) (emphasis in original), including the initial proposed rate, see FPC v. Hunt, 376 U.S. 515, 521 (1964); Atlantic Refining Co. v. Public Serv. Comm'n, 360 U.S. 378, 390-92, 3 L. Ed. 2d 1312, 79 S. Ct. 1246 (1952), and effects on competition, see Northern Natural Gas Co. v. FPC, 130 App. D.C. 220, 399 F.2d 953, 958, 961 (D.C. Cir. 1968). But the Secretary of Energy's Policy Guidelines require FERC to exercise its section 7 authority over imports "in a manner consistent with the gas import policy determinations established by the Secretary." Policy Guidelines, 49 Fed. Reg. at 6688. As we have stated, "the Commission cannot, consistent with the [Secretary's] Delegation Orders, take actions inconsistent with the terms, conditions, or policy considerations reflected in [DOE/FE's] section 3 import authorization." Wisconsin Gas Co., 770 F.2d at 1155-56.

In its brief before this court, FERC [**54] contends that under this regulatory framework it lacked authority to respond to the domestic producers' concerns. It cites the conclusions set forth in the Preliminary Order and argues that our recent decisions in ANR and Transcanada support its position. Significantly, however, although the Preliminary Order correctly asserted that FERC had no jurisdiction to modify the underlying import agreements approved by DOE/FE, see Preliminary Order at 61,373-74, it did not contend that the Commission lacked authority to adjust Iroquois' transportation rates in order to offset the alleged competitive advantage. Under our precedents, it does not appear to us that [**1122] DOE/FE's decision would have prevented FERC from doing so.

In ANR, we affirmed the Commission's decision not to make an independent "public interest" finding regarding the importation of Canadian gas under section 7 on the ground that DOE/FE had already made such a finding pursuant to its section 3 authority. See ANR, 876 F.2d 132 at 132-33 . We recognized that under Transco "the Commission's transportation jurisdiction may reach issues beyond those directly concerned with the transportation," [**55] id. at 132, but held that when another federal agency has jurisdiction over a question and has decided that question, FERC has no obligation to duplicate the other agency's efforts. See id. ("It would be a considerable stretch from [Transco] to say that, in certifying transportation that is necessary to carry out a sale, the Commission is required to reconsider the very aspects of the sale that have been assessed by an agency specifically vested by Congress with authority over the subject."). We distinguished between FERC's direct consideration of the validity of import contracts approved by DOE/FE (which ANR petitioners apparently sought) and its consideration of other issues (whether or not also considered by DOE/FE) when determining matters such as transportation rates within the Commission's jurisdiction. See id.

This distinction proved decisive in Transcanada. That case presented two questions regarding FERC's jurisdiction vis-a-vis DOE/FE. The first was whether FERC properly declined to adjust the terms of an agreement between a domestic pipeline and its customer for the resale of Canadian gas. The customer argued that the pipeline could [**56] have acquired the gas from its Canadian supplier on better terms and should not be permitted to pass on to domestic consumers costs that were "imprudently" incurred. Transcanada, 878 F.2d at 406. We upheld as reasonable FERC's conclusion that it lacked authority to perform an independent "prudence" review of the terms of import contracts already authorized by DOE/FE, agreeing with the Commission that such review was prohibited because it could produce a decision inconsistent with DOE/FE's determinations. See id. at 407.

The second question in Transcanada was whether FERC acted within its authority when, in Order No. 256,
it disallowed a pipeline to pass through to resell customers Canadian costs as-billed. In response, we held that DOE/FE's import authorizations did not deprive the Commission of jurisdiction. We observed that FERC's assertion of authority to reallocate costs in domestic sales contracts between the demand and commodity components "did not require it to reevaluate the import contracts themselves." Id. at 409. In other words, the remedy adopted in Order No. 256 only required the Commission to examine the terms of the resale agreements before it and to ensure, by imposing a modified-fixed-variable rate structure, that Canadian gas was "treated . . . no differently" from domestic gas. Id. at 410. We also noted that DOE/FE, in its authorization of the underlying import agreements, had recognized FERC's authority to take such corrective action, and we therefore concluded that FERC's reclassification of costs was not inconsistent with DOE/FE's determinations. See id. at 409-10. In sum, we determined that DOE/FE's finding that the imported gas would be competitive (that is, that there would be a market for it) did not preclude the Commission from making its own finding regarding anticompetitive effects. See id.

The question into which category - ANR"prudence review" (no jurisdiction) or Order No. 256 (jurisdiction) - the Iroquois "rate tilt" issue falls is rather subtle, but we are persuaded that DOE/FE's authorization of the import agreements in this case did not preclude FERC from making an otherwise appropriate adjustment to Iroquois' rates. To be sure, unlike the situation in Order No. 256, DOE/FE did specifically address the anticompetitive effects argument here. And while in Order No. 256 the Commission simply looked at the rate structure before it and found that it deviated from domestic policy, in this case FERC would have had to examine the rate design contained in the import agreements (and approved by DOE/FE) to justify departing from the standard modified-fixed-variable methodology proposed by Iroquois' proponents. Still, our case resembles Order No. 256 in another important respect emphasized in Transcanada: DOE/FE explicitly left open the possibility of FERC's responding to the domestic producers' concerns. We think that by citing FERC's 1989 Policy Statement and by declining to take corrective action in part because of FERC's "ongoing review of pipeline rate design," DOE/FE acknowledged and deferred to FERC's authority to remedy problems arising out of differences between Canadian and domestic rate structures. We therefore do not believe that FERC was foreclosed by DOE/FE's decision from adjusting Iroquois' rates.

We would thus be obliged to remand if, as the Commission's brief suggests, FERC actually based its decision not to adopt the domestic producers' proposals on a purported lack of jurisdiction. [**59] But FERC's only discussion of the jurisdictional question appears in its Preliminary Order, and in that order FERC specifically stated that its views on the appropriate rate design were only tentative and would be reconsidered in the August hearing. See Preliminary Order at 61,343-44. The Commission's final decision on this matter, Order No. 357, does not make the jurisdictional argument, 11 nor does the denial of rehearing, Order No. 357A, mention DOE/FE's authority over imports. For this reason, the jurisdictional issue cannot be a basis for either denying the petition for review or for remanding. See SEC v. Chenery Corp., 318 U.S. 80, 87, 87 L. Ed. 626, 63 S. Ct. 454 (1943). 12 We must instead examine the rationale actually presented in FERC's final order.

11 In the section devoted to the "rate tilt" issue, the only significant reference to DOE/FE appears in an expository subsection labeled "Legal framework," in which the Commission explained in general terms the delegations to DOE/FE and to FERC. See Order No. 357 at 61,700.

12 Just as under Chenery, we do not give an agency the benefit of a post hoc rationale of counsel, an agency is not invariably splattered by its counsel's awkward brush strokes.

[**60] The Commission's decision in Order No. 357 not to adjust Iroquois' rates rests upon administrative convenience. When evaluating proposals for new supply projects, the Commission says, its policy is "to encourage proposals which increase the supply options of gas buyers and enhance competition," not to "protect existing suppliers from competition." Order No. 357 at 61,701. FERC does not attempt to adjust for all rate differentials between competing pipelines; such differentials may exist for a variety of reasons and are, according to the Commission, administratively difficult to identify. FERC's policy is simply to ensure that a new pipeline's rate design does not give it an "unfair advantage." Id. at 61,701-02. It reasoned that it accomplished this goal here by imposing the same rate structure on Iroquois that it does on other domestic pipelines. See id. at 61,701-03.

The domestic producers do not take issue with FERC's general policy against attempting to equalize all
rate differentials between pipelines. Rather, they seem to contend that the Commission should have made an exception in this case because the competitive distortions arising from the interaction of Canadian [**61] and domestic rate structures are so large. The Commission's failure to do so, they further maintain, is inconsistent with Order No. 256. They also suggest that in refusing to consider the potential anticompetitive effects of the Iroquois project, FERC violated its statutory duty to take all public interest factors into account before issuing a section 7 certificate.

We think that the last argument mischaracterizes the Commission's decision. As the domestic producers themselves acknowledge, the Commission assumed that the alleged anticompetitive effects might result but declined for other reasons to adopt the proposed solutions. As to the suggestion that FERC erred in declining to depart from its general policy and adjust Iroquois' rates, the Commission explained [*1124] that it could not do so consistently with its responsibilities under the Free Trade Agreement. According to the Commission, consistency with the Agreement's "national treatment" obligation - which prohibits FERC from treating Canadian gas supplies less favorably than domestic gas supplies, see Free Trade Agreement, pt. 1, ch. 1, art. 105, pt. 2, ch. 5, art. 501, 27 I.L.M. at 294, 314 (incorporating the definition [**62] of "national treatment" in part II, article III of the General Agreement on Tariffs and Trade, 61 Stat. A5, A18-A19 (1947)) - would require FERC to make the proposed detailed adjustments not only to pipelines transporting Canadian gas, but also to all domestic projects. FERC would have to analyze the demand and commodity charges in the transportation rates and underlying sales contracts for every project, and, if the commodity charges were lower than those of competitors, make the appropriate adjustment. It reasoned that such a detailed analysis would be inappropriate because it would create enormous administrative difficulties, including problems associated with obtaining information about rates subject to Canadian jurisdiction. See Order No. 357 at 61,703-05.

The Commission distinguished this situation from the reallocation of costs undertaken in Order No. 256, which did not require examination of sales contracts to which the pipeline was not a party. See id. at 61,704. Order No. 357A reiterated these rationales, observing that in their petition for rehearing the domestic producers had failed to confront the practical problems that their proposals entailed. See Order [**63] No. 357A at 61,357-59.

FERC's explanation, although perhaps somewhat strained, passes the test of reasonableness. The Commission does not maintain that the Free Trade Agreement deprives it of all power to respond to the "rate tilt" problem; nor does the Commission argue that the Agreement requires it to adhere to a modified-fixed-variable rate design in every circumstance. As petitioners point out, FERC recently initiated rulemaking proceedings that include a proposal to require domestic pipelines to adopt the fixed-variable methodology, see Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation, 56 FR 38,372, 38,383 -85 (1991) - a forum, we note, in which it would be appropriate for the Commission to consider systemic solutions to the domestic producers' concerns. FERC only argues here that its policy is not to undertake complex analyses to equalize all rate differentials between pipelines and that it cannot, consistently with the Free Trade Agreement, adopt the proposed conditions because they would (when applied to all domestic projects, as the "national treatment" obligation would require) result in a [**64] regulatory morass. The domestic producers deny this, but their denial is rather mushy. They "strongly doubt" that FERC would discover similarly significant distortions resulting directly from FERC's own policies in other contexts, but they have not refuted the Commission's assertion that the Free Trade Agreement would require it to apply the analysis proposed here to all domestic projects. And they have not rebutted FERC's argument that enormous administrative problems would follow.

We also do not believe that the Commission's refusal to adjust Iroquois' rates on these grounds is inconsistent with Order No. 256. In each case FERC required pipelines to adhere to domestic rate design policies. As FERC emphasized, in Order No. 256 it had to consider the anticompetitive effects of Canadian rate structures because those structures were incorporated into a domestic sales contract directly before the Commission; just as it did here, FERC only considered the particular rates before it. The corrective action taken in Order No. 256, moreover, did not give rise to the types of administrative difficulties present here. We therefore affirm the Commission's decision on the "rate tilt" issue.

IV

[**65] The third and final petition for review was submitted by the Texas Eastern Transmission Company,
one of four American pipeline companies with an interest in the Iroquois Limited Partnership. See supra p. 9. Although Texas Eastern's [*1125] system is not physically connected to the Iroquois pipeline, Texas Eastern intends to participate in the Project by exchanging gas with Iroquois. Several of Iroquois' customers are in New Jersey, but since the Iroquois pipeline will terminate on Long Island, they cannot be directly served by the pipeline. Texas Eastern, which is physically connected to the New Jersey LDCs, has several customers in New York who could be served by the Iroquois. Accordingly, Texas Eastern has agreed to deliver domestic gas purchased by its customers in New York City to Iroquois' New Jersey customers in return for Iroquois delivering Canadian gas purchased by the New Jersey LDCs to Texas Eastern's New York customers. For its part in this "no fee" exchange, Texas Eastern plans to charge a small fee.

Section 7(c) of the Natural Gas Act requires companies wishing to transport gas to secure "a certificate of public convenience and necessity authorizing such acts or operations." [*66] 15 U.S.C. § 717j(e); see also 18 C.F.R. § 284.1(a) (defining transportation to include exchanges). The Commission must issue such certificates if three conditions are satisfied: "the applicant is able and willing properly to do the acts and to perform the service proposed," the applicant will follow the Commission's rules and regulations, and the proposed service "is or will be required by the present or future public convenience or necessity." Natural Gas Act § 7(e), 15 U.S.C. § 717j(e). The question here is whether Texas Eastern's application satisfies the third criteria.

Until recently, the Commission issued section 7(c) certificates primarily for specific transactions, like the proposed Texas Eastern-Iroquois exchange. Order No. 357 at 61,730. In 1985, hoping to open up the natural gas markets to greater competition by allowing LDCs to purchase natural gas directly from the wellhead, the Commission began issuing "blanket" certificates. See, e.g., Associated Gas Distrib. v. FERC, 824 F.2d 981, 993 (D.C. Cir. 1987), cert. denied, 485 U.S. 1006 (1988). These new certificates relieve their holders from the time and expense of seeking individual [*67] certifications; in return for this regulatory relief, holders of blanket certificates must provide transportation on a nondiscriminatory, open-access basis. ANR Pipeline Co. v. FERC, 277 App. D.C. 365, 876 F.2d 124, 127-28 (D.C. Cir. 1989); Associated Gas Distribs. v. FERC, 824 F.2d at 996. (Although section 4(b) of the Natural Gas Act, 15 U.S.C. § 717c(b), prohibits undue discrimination among customers, it does not prohibit a pipeline in all circumstances from refusing "to carry based on the would-be shipper's selling in competition with the pipeline." ANR Pipeline Co. v. FERC, 876 F.2d at 128 (citation omitted).) Finding it in the public interest to avoid processing redundant applications, and perhaps as well to encourage open-access transportation, the Commission has adopted, and this court has approved, a policy of denying case-specific section 7(c) certificates to pipelines that can already perform the same services under a blanket certificate. Tennessee Gas Pipeline Co. v. FERC, 283 App. D.C. 204, 898 F.2d 801, 804 (D.C. Cir. 1990); see also ANR Pipeline Co., 876 F.2d at 129 n.3.

Based upon that policy, the Commission [*68] reasoned that "no legal, policy, or administrative purpose would be served by continuing to process Texas Eastern's application for case-specific authority to perform the proposed exchange service, since Texas Eastern has full authority to perform under its blanket certificate." Preliminary Order at 61,396 (citation omitted); Order No. 357 at 61,731. The Commission acknowledged that it had in the past departed from this policy and granted case-specific certificates to pipelines already holding blanket certificates, but it noted that in each of those cases there had been construction related to the proposed transportation services. Order No. 357 at 61,731-32. In such cases, the Commission observed, it was appropriate to grant a case-specific certificate "as a basis for determining the term of depreciation of the facilities to be constructed or for allocation of their costs to particular beneficiaries of that transportation." Id. at 71,732. The Commission [*1126] found that exception inapplicable here.

Texas Eastern seems to object to the Commission's decision on two grounds. 13 First, Texas Eastern argues that since its application is related to the construction of the Iroquois pipeline, [*69] it qualifies for the construction exception. However, the construction exception is only available if the construction is integrally related to the proposed transportation services. Tennessee Gas Pipeline Co. v. FERC, 898 F.2d at 805. In other words, the "public's convenience or necessity" requires the Commission to invoke the construction exception only when by doing so the Commission will insure a more equitable distribution of costs between the pipeline
and its customers (through special depreciation rates) or between customers (by allocating construction expenses to those specifically benefiting from the construction). Order No. 357 at 61,732. Since neither consideration applies to Texas Eastern's proposed exchange, the Commission found the fact that the proposed exchange is tangentially related to a construction project to be irrelevant. Moreover, since the Commission is charged with administering the Natural Gas Act, and since its interpretation of that Act is reasonable, we defer to it. K Mart Corp. v. Cartier, Inc., 486 U.S. 281, 291-92, 100 L. Ed. 2d 313, 108 S. Ct. 1811, 6 U.S.P.Q. 2d (BNA) 1897 (1988); Arkansas Louisiana Gas Co. v. FERC, 898 F.2d at 804.

13 Texas Eastern also tries to make other points. For example, it suggests that by requiring it to perform the exchange with Iroquois under its blanket certificate the Commission is somehow precluding it from charging already approved rates on other exchanges authorized under case-specific certificates. It is, however, undisputed that the blanket certificate will not affect those other exchanges until the case-specific certificates governing them expire. As a consequence, like the Commission, we are at a loss to see how the Commission's decision does what Texas Eastern claims it does. Order No. 357A at 61,352. If the petitioner hopes for a favorable ruling on judicial review, it must at the very least make its criticisms of the agency's decision comprehensible.

[**70] Second, Texas Eastern argues that its blanket certificate does not cover the no-fee exchange services it plans to perform because it has not yet filed the tariff required for these charges under section 4(c) of the Natural Gas Act. 15 U.S.C. § 717c(c); see generally Arkansas Louisiana Gas Co. v. Hall, 453 U.S. 571, 577-78, 69 L. Ed. 2d 856, 101 S. Ct. 2925 (1981). It is, however, hard to see how the presence or absence of such a filing makes any difference in a section 7(c) proceeding. After all, even if Texas Eastern were granted a case-specific certificate for the proposed exchange, it would still have to file a tariff before performing those services. The Commission reads section 4 rate filings and section 7(c) certifications as imposing entirely distinct obligations. Order No. 357A at 61,352. Since this reading is reasonable, we uphold it and deny Texas Eastern's petition for review. 14

14 Texas Eastern also notes that in recently approving a case-specific certificate for Iroquois, which holds a blanket certificate, the Commission mentioned that Iroquois had not yet filed a tariff for those services. Iroquois Gas Transmission Sys., 55 F.E.R.C. 61,276, at 61,885 (1991); Iroquois Gas Transmission Sys., 54 F.E.R.C. 61,285, at 61,812 (1991). While this is true, the Commission did not find the lack of a filed tariff to justify granting a case-specific certificate. Instead, it considered the lack of a tariff in the course of determining whether to invoke the construction exception. Application of that exception is not automatic: the Commission has ruled only that when transportation services are integrally related to new construction, "transaction specific certificate authority may well be appropriate." Tennessee Gas Pipeline Co., 43 F.E.R.C. 61,042, at 61,126 (1988) (emphasis added). Accordingly, just as the Commission considered in deciding whether to exercise its discretion that "there is significant new construction involved which has yet to be completed," it also considered the fact that "the tariff by which transportation would be accepted and scheduled is not yet in effect." Iroquois Transmission Sys., 54 F.E.R.C. at 61,812.

[**71] The petitions for review are denied.
PAUL L. TESSIER, M.D., Plaintiff v. PLASTIC SURGERY SPECIALISTS, INC., WILLIAM P. MAGEE, JR., M.D., JONATHON S. JACOBS, M.D., CHARLES E. HORTON, M.D., JEROME E. ADAMSON, M.D., JAMES H. CARRAWAY, M.D., JOHN B. MCCRAW, M.D., J. CRAIG MERRILL, M.D., and NEIL M. BIALKIN, Defendants

Civil Action No. 89-399-N

UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF VIRGINIA, NORFOLK DIVISION

731 F. Supp. 724; 1990 U.S. Dist. LEXIS 2310

February 20, 1990, Decided


For Neil M. Bialkin: Deborah L. Mancoll/John M. Ryan, Vandeventer, Black, Meredith & Martin, Norfolk, Virginia.


For David A. Gilbert: Hunter W. Sims, Jr., Esquire, Kaufman and Canoles, Norfolk, Virginia.


JUDGES: J. Calvitt Clarke, Jr., United States District Judge.

OPINION BY: CLARKE, JR.

ORDER

J. CALVITT CLARK, JR., UNITED STATES DISTRICT JUDGE.

This matter arises on defendants' cross-motions to disqualify counsel. Defendants Charles E. Horton, M.D., Jerome E. Adamson, M.D., and John B. McCraw, M.D. ["the Horton group"], by their counsel Thomas J. Harlan, Jr., move this Court for an Order disqualifying Gregory Stillman, Esquire and the law firm of Hunton & Williams from representing Plastic Surgery Specialists, Inc. ["PSSI"] in the pending action. Correspondingly, defendant William P. Magee, Jr., M.D., by his counsel [**2] Thomas B. Shuttleworth, moves this Court for an Order disqualifying Thomas J. Harlan, Jr., Esquire and the law firm of Thomas J. Harlan, Jr. and Associates from representing the Horton group in the pending action. In the alternative, Dr. Magee moves this Court for an Order disqualifying Mr. Harlan and the law firm Harlan and Associates from representing the Horton group in the cross-claim that has been filed against Dr. Magee and others by the Horton group. All non-moving parties have responded in opposition and argument was heard on September 18, 1989. Accordingly, this matter is ripe for
Facts

The following are the pertinent facts taken from the uncontradicted statements in the briefs, the pleadings and affidavits filed with the Court and from arguments before the Court.

Defendant PSSI was a professional corporation under Virginia law that specialized in plastic surgery. The eight physician defendants were formerly shareholders and members of the operating board of directors. Defendant Neil M. Bialkin was the business administrator of PSSI.

Plaintiff Paul L. Tessier, M.D., a citizen of France, is a world renowned cranio-facial surgeon. He began his association with PSSI in November, 1983. Since that time he has travelled to the United States once or twice a year to perform surgery in Norfolk for two week periods. In the underlying action, Tessier claims that he was not fully and fairly compensated for the services he performed on behalf of PSSI.

Due to irreconcilable differences among the physicians regarding the business affairs of PSSI, the shareholder physicians split into two equally divided groups. One group comprising Dr. Magee, Dr. Gilbert, Dr. Jacobs, and Dr. Merrill will be referred to as the Magee group and the other group comprising Dr. Horton, Dr. Adamson, Dr. McCraw, and Dr. Carraway will be referred to as the Horton group. As a result, the Board of Directors became deadlocked. A petition for involuntary dissolution was filed in the Circuit Court for the City of Norfolk. The Circuit Court appointed H. Leon Hodges as custodian. Ultimately, the parties reached an agreement to voluntarily dissolve PSSI as of December 31, 1988.

The dissolution of PSSI remains governed by the Agreement of Reorganization and Dissolution executed by all shareholders. Under the heading "Assumption of Liabilities," section 1.2 of the Agreement of Reorganization states:

(a) As of the Effective Time, each of the New Corporations shall assume and agree to pay all of the liabilities, whether fixed or contingent, known or unknown, now existing or hereafter arising, relating to Section 1.1 hereof and relating to the Shareholders to be employed by such New Corporation (the "Related Liabilities"), including, without limitation, the following:

(iv) liabilities determined to have been caused by or arising from the acts or omissions of the Shareholders to be employed by such New Corporation prior to the Effective Time, including without limitation any medical malpractice claims and any acts or omissions of such Shareholders relating to federal, state or third-party payor reimbursement claims. All parties agree that the purpose of the Section 1.2(a)(iv) is to place liability on the particular New Corporation which employs the Shareholder whose conduct gives rise to or causes the liability.

Section 1.2(a)(iv) provides that any judgment against PSSI caused by an individual shareholder will be borne by that individual shareholder and the new entity or corporation under whose banner he is now practicing.

Hunton & Williams began representing PSSI in January, 1988 and represented PSSI in the dissolution proceedings.

In April 1989, Dr. Tessier filed an action in this Court against Dr. Magee and Dr. Magee's "New Corporation," Plastic Surgery Associates, Inc. ("PSA"). The action sought injunctive relief prohibiting the use of Dr. Tessier's name on PSA's stationary and the production of patient records. Hunton & Williams defended Dr. Magee and PSA in that case, which has now been settled.

In the following month, on May 22, 1989, Dr. Tessier filed the present action again in this Court. As defendants he named PSSI, PSSI's former shareholders (alleging fraud against Dr. Magee and others) and PSSI's administrator Mr. Bialkin. As stated above, Dr. Tessier seeks full and fair compensation for the services he performed while associated with PSSI. Hunton & Williams represents PSSI in this action. Later, on June 22, 1989 the Horton group defendants, by their counsel Mr. Harlan, filed a cross-claim against defendants Dr. Magee, Mr. Bialkin, and PSSI. In no uncertain terms, the
Horton group acknowledges that Dr. Tessier may have been defrauded and charges Dr. Magee and Mr. Bialkin with orchestrating a fraudulent scheme designed to deprive Dr. Tessier of due compensation. The Horton group also looks to PSSI for indemnification of legal costs should they prevail in their defense of the claims asserted against them by Dr. Tessier.

During 1983 and 1984, Mr. Harlan, then with the law firm of Dudley & Pincus, also provided legal services for PSSI. Mr. Bialkin had requested Montgomery Knight, Esquire, also of Dudley & Pincus, to draft some proposed personnel contracts for the corporation. However, disagreements arose between Mr. Knight and Mr. Bialkin concerning the timeliness of Mr. Knight's work. Mr. Harlan mediated the dispute and ultimately decided to sever his firm's legal relationship with Mr. Bialkin and PSSI. Mr. Harlan and the law firm of Thomas J. Harlan & Associates have continually represented the Horton group defendants throughout the state court dissolution proceedings and the present matter.

The Motion to Disqualify Mr. Stillman and the Law Firm of Hunton & Williams

The Horton group, by their counsel Mr. Harlan, contends that the Virginia Code of Professional Responsibility prohibits Mr. Stillman and the law firm of Hunton & Williams from representing PSSI in the pending action. Specifically, they allege that Mr. Stillman's prior representation of Dr. Magee and PSA [hereinafter referred to as "the PSA litigation"] prohibits him from representing PSSI in the instant matter because it would constitute impermissible successive representation within the meaning of Disciplinary Rule 5-105(D). 2

1 As stated above, the Horton group of defendants consists of Dr. Horton, Mr. Adamson and Dr. McCraw. They allege that prior to the dissolution of PSSI, the shareholder/directors had split into two equal factions. The Horton faction was comprised of Dr. Horton, Mr. Adamson, Dr. McCraw, and Dr. Carraway; the Magee faction was comprised of Dr. Magee, Dr. Gilbert, Dr. Jacobs, and Dr. Merrill. The inability of these two factions to make business decisions together led to the dissolution of PSSI. The Horton group alleges that the termination of the law firm of Willcox & Savage and the subsequent retention of the law firm of Hunton & Williams as corporate counsel was a unilateral act of then-President Dr. Magee and was approved only by the Magee faction.

2 Initially, the Horton group contended that Mr. Stillman represented not only PSSI, but also Dr. Jacobs and Dr. Carraway as well. If true, such attorney-client relationships would raise further ethical concerns about multiple and simultaneous representation. However, Mr. Stillman has stated in a letter to this Court that he represents only PSSI in the present case. Thus, the present issue, as framed by counsel, is one of successive representation only. The Court will, however, address an actual conflict arising in a multiple representation context below.

Mr. Stillman has not informed the Court of whether PSA remains a client of Hunton & Williams. Presumably, PSA would, if necessary, be represented by the same law firm as Dr. Magee. Dr. Magee is represented by Mr. Shuttleworth of the law firm of Shuttleworth, Ruloff, Giordano & Kahle in this litigation.

The ethical standards of practice before this court are set out in the Virginia Code of Professional Responsibility. See Local Rules of Practice, United States District Court for the Eastern District of Virginia, Rule 7(l) (1989). Disciplinary Rule 5-105(D) states:

A lawyer who has represented a client in a matter shall not thereafter represent another person in the same or substantially related matter if the interests of that person is adverse in any material respects to the interest of the former client unless the former client consents after disclosure.

Va.Code Prof. Resp. DR 5-105(D) (emphasis added).

[**8] The problem implicated by successive representation is the potential for the use of confidences gained from a former client to the detriment of that client or the failure to use information favorable to the present client in order to protect the confidentiality of the former client. The Horton group argues that here, pursuant to the
Reorganization Agreement, if a judgment is entered against PSSI, and Dr. Magee is found to have caused the judgment to be so entered, then Mr. Stillman will be in the inappropriate position of having to sue his former client in order to realize a judgment for his current client. Additionally, the Horton group argues that Canon 9 of the Code of Professional Responsibility mandates disqualification in this matter. Canon 9 states that "the lawyer should avoid even the appearance of professional impropriety." They contend that the present situation may appear unethical to laymen and thereby erode public confidence in the integrity of the judicial system.

Hunton & Williams responds by noting that they were hired by Mr. H. Leon Hodges, the current custodian of PSSI. They argue that Mr. Hodges's right to freely choose counsel should be vigorously protected, especially [**9] in light of the recent practice to employ the motion to disqualify counsel as a litigation sword instead of an ethical shield. With respect to the successive representation allegation, Hunton & Williams maintains that the matters at issue in the PSA litigation and in this action are not "substantially related." And that, even if they were, there is no "actual conflict" to warrant disqualification. Finally, Hunton & Williams contends that the Horton group's "appearance of impropriety" argument is mere makeweight. 3

**3** Hunton & Williams also argues that the Horton group lacks standing to challenge PSSI's choice of counsel. They assert that only PSSI through its custodian has the right to object to any successive representation. Disciplinary Rule 1-103 and Ethical Consideration 1-4 of the Virginia Code of Professional Responsibility provide that as officers of the court, all attorneys have a continuing obligation to disclose to the court any violation of the rules of professional conduct. See United States v. Clarkson, 567 F.2d 270, 271-72 n. 1 (4th Cir. 1977) ("Any member of the bar aware of the facts justifying a disqualification of counsel is obligated to call it to the attention of the court."). The Fourth, Fifth, and First Circuit Courts of Appeal have held that disqualification may properly be sought by adverse counsel even though he or she is not representing the aggrieved client. Id.; Brown & Williamson Tobacco Corp. v. Daniel Int'l Corp., 563 F.2d 671, 673 (5th Cir. 1977); Kevlik v. Goldstein, 724 F.2d 844, 848 (1st Cir. 1984).

Furthermore, as will be discussed later in this opinion, each Horton group physician is a de facto client of Hunton & Williams. The Court holds that the moving parties have the requisite standing to bring motions for disqualification of counsel based on successive representation.

[***10] [**729] Analysis

The potential variety of interests which may dilute an attorney's loyalty to a client is measureless. Often in the course of complex litigation an attorney will fail to identify what others clearly recognize as an irreconcilable conflict among interests. Chief among the reasons for avoiding conflicts of interest is the preservation of the public's confidence in the integrity of lawyers and the judicial system. To allow a conflict to remain unaddressed until an affected party complains about the quality of justice he or she has received is to betray the public trust granted to the bar as a self-regulating organization.

The Court is charged with the duty and responsibility of supervising the conduct of attorneys who appear before it. Kevlik, 724 F.2d at 847; Trust Corp. of Montana v. Piper Aircraft Corp., 701 F.2d 85, 87 (9th Cir. 1983); United States v. Agosta, 675 F.2d 965, 969 (8th Cir.), cert. denied, 459 U.S. 834, 103 S. Ct. 77, 74 L. Ed. 2d 74 (1982); Hull v. Celanese Corp., 513 F.2d 568, 571 (2d Cir. 1975). The Court is not unmindful of the recent practice indulged in by some to use disqualification motions for purely strategic purposes, see, e.g., Smith v. Whatcott, 757 [**11] F.2d 1098, 1099-1100 (10th Cir. 1985); Melamed v. ITT Continental Baking Co., 592 F.2d 290, 295 6th Cir. 1979); International Electronics Corp. v. Flanzer, 527 F.2d 1288, 1289 (2d Cir. 1975), and that courts should not be oblivious to this fact. Appropriately, the Fourth Circuit has cautioned against a mechanical application of the Virginia Code of Professional Responsibility to all situations. 4

4 In Aetna Cas. & Sur. Co. v. United States, 570 F.2d 1197 (4th Cir.), cert. denied, 439 U.S. 821, 58 L. Ed. 2d 113, 99 S. Ct. 87 (1978) the Court of Appeals quoted with approval the following language from International Electronics Corp. v. Flanzer, 527 F.2d 1288, 1293 (2d Cir. 1975) (the Second Circuit itself was quoting a passage from an amicus curiae brief filed by the Connecticut Bar Association):
It behooves this court, therefore, while mindful of the existing Code, to examine afresh the problems sought to be met by that Code, to weigh for itself what those problems are, how real in the practical world they are in fact, and whether a mechanical and didactic application of the Code to all situations automatically might not be productive of more harm than good, by requiring that client and the judicial system to sacrifice more than the value of the presumed benefits.

*Aetna*, 570 F.2d at 1202.

[**12**] The Court is also aware that the disqualification of a party's chosen counsel is a serious matter which cannot be based on imagined scenarios of conflict. See *Richmond Hilton Associates v. City of Richmond*, 690 F.2d 1086, 1089 (4th Cir. 1982) ("actual or likely" conflict of interest required); *Aetna*, 570 F.2d at 1200 (where "practical considerations" eliminated any possibility of conflict, district court's hypothesis based on conjecture will not support granting motion to disqualify counsel). Thus, the moving party bears a "high standard of proof" to show that disqualification is warranted. *Government of India v. Cook Industries, Inc.*, 369 F.2d 737, 739 (2d Cir. 1978); see also *Evans v. Artek Systems Corp.*, 715 F.2d 788, 794 (2d Cir. 1983).

The high standard of proof is fitting in light of the party's right to freely choose counsel, *Silver Chrysler Plymouth, Inc. v. Chrysler Motors Corp.*, 518 F.2d 751, 753 (2d Cir. 1975), and the consequent loss of time and money incurred in being compelled to retain new counsel. See *Government of India*, 569 F.2d at 737. However, this Court has held that the right of one to retain counsel of his choosing is "secondary in importance [*13*] to the Court's duty to maintain the highest ethical standards of professional conduct to insure and preserve trust in the integrity of the bar." *In re Asbestos Cases*, 514 F. Supp. 914, 925 (E.D.Va. 1981), citing *Silver Chrysler*, 518 F.2d at 757; *Hull v. Celanese Corp.*, 513 F.2d 568, 569 (2d Cir. 1975); *Telos Inc. v. Hawaiian Telephone Co.*, 397 F. Supp. 1314 (D.Haw. 1975). There must be a balance between the client's free choice of counsel and the maintenance of the highest ethical and professional standards in the legal community. *In re Asbestos Cases*, 514 F. Supp. at 914.

The Disciplinary Rules of the Virginia Code of Professional Responsibility are mandatory in character. The Rules state [*730*] the "minimum level of conduct below which no lawyer can fall without being subject to disciplinary action." Preamble, Virginia Code of Professional Responsibility. Disciplinary Rule 5-105(A) states that in the absence of consent, "[a] lawyer shall decline proffered employment if the exercise of his independent professional judgment in behalf of a client will be or is likely to be adversely affected by the acceptance of the proffered employment," and Section (D) adds that "[a] lawyer [*14*] who has represented a client in a matter shall not thereafter represent another person in the same or substantially related matter if the interest of that person is adverse in any material respect to the interest of the former client. . . ." The relevant test under Disciplinary Rule 5-105(D) is whether the matters at issue in the PSA litigation are "substantially related" to the matters at issue in the present litigation.

The "substantially related" test was articulated in the seminal case *T.C. Theatre Corp. v. Warner Bros. Pictures, Inc.*, 113 F. Supp. 265 (S.D.N.Y. 1953) and adopted by most of the Circuit Courts of Appeal which have addressed the question of attorney disqualification in the successive representation context. See *Johnston v. Harris County Flood Control District*, 869 F.2d 1565, 1569 (5th Cir. 1989); *Cox v. American Cast Iron Pipe Co.*, 847 F.2d 725, 728 (11th Cir. 1988); *Kevlik v. Goldstein*, 724 F.2d 844, 850 (1st Cir. 1984); *Analytica, Inc. v. NPD Research, Inc.*, 708 F.2d 1263, 1266 (7th Cir. 1983) ("a lawyer may not represent an adversary of his former client if the subject matter of the two representations is 'substantially related,' which means: [*15*] if the lawyer could have obtained confidential information in the first representation that would have been relevant in the second."); *Emile Industries, Inc. v. Patentex, Inc.*, 478 F.2d 562, 570 (2d Cir. 1973). It is a two-pronged test, the movant must establish both: (1) that an attorney-client relationship existed between the alleged former client, 5 and (2) that the former representation and the current controversy are substantially related. *Allegaert v. Perot*, 565 F.2d 246, 250 (2d Cir. 1977) ("before the substantial relationship test is even implicated, it must be shown that the attorney was in a position where he could have received
information which his former client might reasonably have assumed the attorney would withhold from his present client."); In re Chantilly Construction Corp., 39 B.R. 466, 469 (Bankr.E.D.Va. 1984). "Substantially related" has been defined to be "identical" or "essentially the same." Government of India, 569 F.2d at 739-40; Williamsburg Wax Museum, Inc. v. Historic Figures, Inc. 501 F. Supp. 326, 328-29 (D.D.C. 1980).

5 There is no dispute that Dr. Magee and PSA are former clients of Hunton & Williams. Therefore, the only question before the Court is whether the PSA litigation and the pending action are substantially related.

[*16] Based on the arguments adduced and on the evidence presented, the Court finds that the PSA litigation, in which Hunton & Williams represented Dr. Magee and his "New Corporation," PSA, is substantially related to the instant action, in which Hunton & Williams represents PSSI.

Hunton & Williams asserts that the PSA litigation dealt solely with the use of Dr. Tessier's name on PSA letterhead and involved different time frames, different causes of action, different legal theories, and different parties. Therefore, they argue, it is not substantially related to this suit. The Court cannot agree.

Clearly the PSA litigation involved more than the misappropriation of Dr. Tessier's name. Dr. Tessier also sought an order requiring Dr. Magee and PSA to deliver the medical records of all the patients whom Dr. Tessier had treated while at PSSI. Tessier v. Magee and Plastic Surgery Associates, Civil Action No. 89-279-N (E.D.Va. Sept. 15, 1989) (Complaint paragraph 25). It was the express intention of Dr. Tessier to continue treating those patients. Id. at paragraphs 12-17. However, it was alleged that Dr. Magee and PSA deliberately undertook to terminate Dr. Tessier's relationship with [*17] those patients and deny him access to them. Id. at paragraph 18. The records were important for [*731] two reasons. The treatment of those patients would no doubt produce a not insignificant future income stream to whomever would be charged with the responsibility of their care. 6 Moreover, the records would reflect any inaccuracies, deliberate or innocent, in billing procedures prior to the PSSI's dissolution. In the present litigation, Dr. Tessier is using the same files to determine if he was fairly compensated for the work he performed on behalf of PSSI. These latter considerations underlie the present action. Furthermore, in determining the issue of removal of the name from the letterhead, it can be assumed that Mr. Stillman of Hunton & Williams would have discussed with Dr. Magee and his faction the nature and extent of the agreement between Dr. Tessier and the American doctors.

6 It is alleged that between November of 1983 and November of 1988, Dr. Tessier performed 163 surgical procedures in Norfolk in association with PSSI.

The two cases are substantially related in other respects. The parties in the PSA litigation are also parties, or potential parties, in the current litigation. [*18] Both suits are the byproducts of the dissolution of PSSI. More importantly, both suits are outgrowths of Dr. Tessier's professional relationship with Dr. Magee and PSA. 7 As former counsel for Dr. Magee and PSA, and present counsel for PSSI, Hunton & Williams will indubitably cross familiar ground in defending Dr. Tessier's claims and in defending against the Horton group's cross-claim.

7 Although PSA is not a named defendant in the present action, it was a named defendant in the earlier action. Pursuant to the Agreement of Reorganization, any judgment against PSSI caused by an individual shareholder will be satisfied by that shareholder's "New Corporation." In the case of Dr. Magee, that would be PSA. If the allegations of fraud against Dr. Magee contained in the Horton group's cross-claim are proven, and PSSI is also found to be liable, counsel for PSSI will have to look to PSA to satisfy any judgment.

While the legal theories employed in both cases are substantively different, the cases do arise from substantially similar facts. Confidential information conveyed in one case does not lose its confidential character because it was not utilized to develop a legal theory in a [*19] subsequent case. The information remains protected whether it is so used or not.

It is well settled that once an attorney-client relationship has been established, an irrebuttable presumption arises that confidential information was conveyed to the attorney in the prior matter. In re Chantilly Construction Corp., citing Westinghouse Elec. Corp. v. Gulf Oil Corp., 588 F.2d 221, 224 n. 3 (7th Cir. 1978); Allegaert v. Perot, 565 F.2d 246, 250 (2d Cir. 1977); In re Asbestos Cases, 514 F. Supp. 914, 921
(E.D.Va. 1981). As counsel to PSSI, Dr. Magee and PSA, Hunton & Williams was in a position to receive confidential information from all former shareholders.

The court finds that the PSA litigation and the present action are "substantially related" and that, therefore, Hunton & Williams might have acquired information which may work to their former client's detriment; namely, Dr. Magee and PSA.

Hunton & Williams argues that even if the Court finds that the two cases are substantially related, the Court cannot grant the motion to disqualify because no "actual conflict" exists between the parties. Hunton & Williams relies on its analysis of two Fourth Circuit decisions interpreting [*20] sections of Disciplinary Rule 5-105. See Aetna Casualty & Surety Co. v. United States, 570 F.2d 1197 (4th Cir.), cert. denied, 439 U.S. 821, 58 L. Ed. 2d 113, 99 S. Ct. 87 (1978) and Richmond Hilton Associates v. City of Richmond, 690 F.2d 1086 (4th Cir. 1982).

In Aetna, an insurance company which had paid claims arising out of an airplane crash brought suit, as subrogee, against the United States and the four air traffic controllers who were on duty at the time of the crash. The United States and the four controllers were represented by the Department of Justice until the district court granted Aetna's motion to disqualify government counsel on the ground that a potential conflict of interest existed between the United States and the individual [*732] controller defendants. In reversing the district court, the Fourth Circuit identified three "practical considerations" which should have entered into the disposition of the motion. First, there was "nothing in the record to support the conclusion of the court that an 'actual conflict exists.'" Id. at 1200. The appeals court stated that the mere existence of multiple defendants does not create a per se conflict of interest on the part of the attorney [*21] representing them. Id. at 1201. The district court could not hypothesize about possible contentions which might be made by each of the four controllers which would allow him to escape liability, but cast blame on his co-defendants. Id. This is especially true, the Fourth Circuit added, in light of Government counsel's representation that "there was no dispute among . . . [the controllers] either with respect to their duties and responsibilities or the details of the plane crash." Id.

Second, the Fourth Circuit found "that there is little or no possibility that the four controllers will incur any personal liability as a result of this litigation" by operation of the Tort Claims Act. Id. And, third, the Court noted that "if the government and the controllers should be held to be jointly liable, the individual defendants would not be required to pay the damages, since a judgment against the United States would automatically bar any contemporaneous or subsequent judgment against them." Id. citing 28 U.S.C. 2676.

Hunton & Williams reads Aetna to require a showing of an "actual conflict" before a motion to disqualify may be granted. The Court finds that this interpretation [*22] is too broad. An application of the "practical considerations" employed by the Aetna court to the operative facts at bar yields a different result.

The "practical considerations" enumerated by the Fourth Circuit were, in effect, guarantees against an actual conflict ever arising. Similar guarantees do not exist in the present action. Here, there is fervent dispute among the defendants about who is responsible for the wrongdoing alleged by Dr. Tessier. Indeed, the detailed cross-claim filed by the Horton group charges defendants Dr. Magee, Dr. Jacobs, Mr. Bialkin and PSSI with fraud. The Horton group admits that Dr. Tessier was not compensated fully and fairly for his services. However, they strenuously deny responsibility for this shortfall and, instead, assert that co-defendants Dr. Magee and Mr. Bialkin are the culpable parties in this lawsuit. Unlike the Aetna defendants, the defendants at bar strongly contest the details of the events which led to the filing of this action.

Also unlike the Aetna defendants, the defendants here may incur personal liability as a result of the litigation. Dr. Tessier seeks to hold the defendants jointly and severally liable. Thus, each [*23] defendant has an incentive to cast blame on the others in order to escape liability. This creates the potential for actual conflict.

Finally, unlike the Aetna defendants who were shielded by 28 U.S.C. 2676, which prevented any recovery against them if the government was also found liable, a judgment against PSSI will also be a judgment against some or all of the individual defendants by operation of the Agreement of Reorganization. The Court finds that the guarantees against an actual conflict in the Aetna case are not present here. The potential for an actual conflict is greater here than in Aetna or Richmond Hilton. 8 If [*733] Dr. Tessier is successful in his suit against PSSI, Hunton & Williams will be placed in the
unseemly quandary of having to sue a former client for indemnification.

8 A similar "practical considerations" analysis will distinguish Richmond Hilton Associates v. City of Richmond, 690 F.2d 1086 (4th Cir. 1982). In that case the district court entered an order prohibiting a law firm from representing certain defendants, mostly public officials, in both their official and individual capacities, but permitting the firm to represent them solely in either capacity. In reversing, the Fourth Circuit noted that there was no conflict between the positions taken by the defendants sued in their official capacities and the defendants sued in both their individual and official capacities with respect to the defense of the lawsuit. In other words, "none of the defendants sued in his official capacity had asserted or intended to assert that the actions of those sued in their individual capacities were ultra vires." Richmond Hilton, 690 F.2d at 1089. In the present action, it is obvious that the positions of the individual defendants differ in regard to the defense of the lawsuit.

[**24] Although Mr. Stillman states that he only represents PSSI in this suit, the law is clear that an attorney's duty of loyalty to a client does not detach when litigation ends. In re Corn Derivatives Antitrust Litigation, 748 F.2d 157 (3d Cir.), cert. denied, Cochrane and Bresnahan v. Plaintiff Class Representatives, 472 U.S. 1008, 86 L. Ed. 2d 718, 105 S. Ct. 2702 (1984). The court recognizes a party's right to retain counsel of his choice, but as stated above, this right must be balanced against the duty of this court to preserve and enhance the public's perception of the fair administration of justice within the legal system. In re Asbestos Cases, 514 F. Supp. at 925. Hunton & Williams' prior representation of the interests of Dr. Magee and PSA could taint the appearance of fairness in this trial and, more importantly, taint the public perception of fairness in this court.

Notwithstanding the Court's interpretations of Aetna and Richmond Hilton, the Court finds that an actual conflict exists between Hunton & Williams and its clients in the current controversy. Mr. Stillman argues in his brief that his client PSSI is a defunct corporation with no assets except accounts receivable of undisclosed amount [**25] which by agreement between the eight individual defendants are being disbursed among the eight on the basis of a formula. Therefore, he maintains, no actual conflict can arise. Mr. Stillman states:

Accordingly, PSSI is a defendant only in a technical sense. As a dissolved corporation, any liability it incurs will pass directly to its former shareholders. Indeed, pursuant to the Reorganization Agreement executed by the shareholders, all liability determined to have been caused by their specific acts or omissions falls squarely on the culpable shareholders whether it be Dr. Magee or Dr. Horton.

Filed letter to the court dated September 26, 1989.

It is clear from this statement that Mr. Stillman is in fact representing the interests individually of the eight shareholders who are each named defendants in this case and are also de facto defendants as the successors of the corporation. It is also clear that these defendants are in a position of conflict in respect to individual responsibility for the payment of any judgment which might be secured by the plaintiff.

As attorney for PSSI, Mr. Stillman will have charge of the strategy followed at the trial. He will have the right to [**26] expect the cooperation of all eight shareholders. He will determine what questions to ask of each shareholder concerning all of his relationships, dealings, conversations, agreements, billing procedures, etc., with the plaintiff. Much of the testimony elicited may bear on the ultimate question of culpability and responsibility for payment of any judgment which might be rendered against PSSI.

A completely neutral attorney who had no prior relationship with any of the stockholders would find it difficult to walk the tightrope and do the balancing act required in representing PSSI in this case. Mr. Stillman, who has already established an attorney-client relationship with one of the competing factions in this case in a matter substantially related to the issues in this case, is carrying so much extra baggage that a balanced and fair performance is virtually unobtainable.

Additionally, three of Mr. Stillman's de facto clients (the Horton group) have unreservedly stated through their attorney that they feel that a conflict exists and that they do not want to be represented by Mr. Stillman. The Court is of the opinion that not only does the appearance of
conflict exist but, in fact, [**27] an actual conflict exists.

Accordingly, the motion to disqualify Gregory Stillman and the law firm of Hunton & Williams GRANTED.

The Motion to Disqualify Mr. Harlan and the Law Firm of Harlan and Associates.

Defendant Dr. Magee, by his counsel Mr. Shuttleworth, contends that the Virginia [*734] Code of Professional Responsibility prohibits Mr. Harlan and the law firm of Harlan and Associates from representing the Horton group in the present action and, in the alternative, in the cross-claim that has been filed against Dr. Magee and others by the Horton group. Specifically, Dr. Magee alleges that Mr. Harlan's prior representation of PSSI and various individuals associated with PSSI during 1983 and 1984 prevents him from representing the Horton group in the instant matter. Such representation, it is argued, would be a form of impermissible successive representation within the meaning of Disciplinary Rule 5-105(D). Dr. Magee further argues that Mr. Harlan's position in the present action violates Canon 9 which states the axiom that a lawyer should avoid even the appearance of professional impropriety.

Mr. Harlan counters by stating that no attorney-client relationship ever existed between [**28] himself and PSSI and that, even if one did, the prior relationship and the instant case are not "substantially related." Applying the "substantial relationship" test as set out above, the Court finds that Mr. Harlan's prior relationship with PSSI is not substantially related to the instant action and, therefore, the motion to disqualify Mr. Harlan and the law firm of Harlan and Associates is DENIED.

In an affidavit filed with the court, Montgomery Knight, Esquire, a former partner of Mr. Harlan's in the law firm of Harlan, Knight, Dudley & Pincus, states that in July of 1983 Mr. Bialkin asked Mr. Knight to draft some personnel contracts for PSSI. Affidavit of Montgomery Knight, Esquire. Shortly thereafter a dispute arose between Mr. Bialkin and Mr. Knight. Id. Mr. Harlan investigated Mr. Bialkin's complaints and determined that it was in the law firm's best interests to discontinue representation of PSSI. First Affidavit of Mr. Harlan.

Mr. Harlan concedes that an attorney-client relationship existed between his former firm and PSSI. However, Mr. Harlan denies that an attorney-client relationship existed between himself and PSSI. The Court believes that Mr. Harlan cannot so easily [**29] segregate himself from the activities of his former firm. Although Mr. Knight's connection to PSSI was limited to the drafting of personnel contracts, First Affidavit of Thomas J. Harlan, Jr., and Mr. Harlan's connection to PSSI was even more tenuous, an attorney-client relationship nonetheless existed. As stated above, once an attorney-client relationship is established, an irrebuttable presumption arises that confidential information was conveyed to an attorney in the prior matter. See In re Chantilly Const. Corp., 36 B.R. 466 (Bankr. 1984), citing Westinghouse Electric Corp. v. Gulf Oil Corp., 588 F.2d 221, 224 n. 3 (7th Cir. 1978); Allegaert v. Perot, 565 F.2d 246, 250 (2d Cir. 1977); In re Asbestos Cases, 514 F. Supp. 914, 921 (E.D.Va.1981). While the information may have been conveyed solely to Mr. Knight, this court has viewed with great skepticism the efficacy of a "Chinese Wall" which, in theory, prevents the communication of confidential information between members of the same firm. See In re Asbestos Cases, 514 F. Supp. at 922-26. Therefore, the Court finds that an attorney-client relationship existed between Mr. Harlan and PSSI.

Having determined that [**30] an attorney-client relationship between Mr. Harlan and PSSI, the Court must decide whether the matters on which Mr. Harlan represented PSSI are "substantially related" to the pending action. The Court finds that they are not. The arm's-length drafting of personnel contracts for PSSI six years ago is not substantially related to litigation which involves an alleged fraudulent billing scheme. Dr. Magee, as the moving party, has failed to come forward with any evidence tending to show a nexus between the 1983-84 relationship and the instant suit. Finding no "substantial relationship" between the two matters, the Court hereby DENIES Dr. Magee's Motion to Disqualify Mr. Harlan and the law firm of Harlan and Associates. For the same reasons stated above, the Court also DENIES Dr. Magee's [*735] alternative motion to disqualify Mr. Harlan and the law firm of Harlan and Associates from representing the Horton group in the cross-claim. 9

9 Dr. Magee also asserts that Mr. Harlan and one or more of his current clients travelled to France to meet with Dr. Tessier with the objective of encouraging the initiation of this litigation. In his
second affidavit filed with the court, Mr. Harlan admits to meeting with Dr. Tessier in Paris, France and the purpose of the meeting: "Because we needed to know who the patients were that Dr. Tessier had operated upon so that we could obtain their files and complete our investigation, it was necessary to meet with Dr. Tessier and to determine what patients he had operated on in Norfolk for the past four or five years. Thus, in September of 1988 while I was on vacation in Paris, I incidentally visited Dr. Tessier alone, without any physician with me at the time. . . . I had spoken to Dr. Tessier, explaining to him our difficulty created by Mr. Bialkin in obtaining records of [PSSI]. . . . I asked him to furnish to us a list of all of his patients that he had operated on at that time so that we could further our investigation." Second Affidavit of Thomas J. Harlan, Jr. In light of the subject matter discussed between Mr. Harlan and Dr. Tessier, a reasonable inference may be made that Dr. Tessier was much closer to filing a lawsuit when Mr. Harlan departed than when he arrived.

Disciplinary Rule 7-103 prohibits an attorney to communicate with a party of adverse interest. It states: "During the course of his representation of a client a lawyer shall not: (1) Communicate or cause another to communicate on the subject of the representation with a party he knows to be represented by a lawyer in that matter unless he has the prior consent of the lawyer representing such other party or is authorized by law to do so."

Dr. Magee has presented no evidence showing that Dr. Tessier was represented by counsel at the time or that Mr. Harlan knew that Dr. Tessier was represented by counsel. More importantly, however, it is at best unclear as to whether the parties were in an adverse setting at this point in time. Considering that the conversation occurred in September of 1988 and that this suit was not filed until May 22, 1989, it is unlikely that the parties were of adverse interest. Accordingly, the court cannot find fault with Mr. Harlan's overseas tete-a-tete.

[**31] Accordingly, for the reasons stated above, the motion to disqualify Gregory Stillman, Esquire and the law firm of Hunton & Williams in the pending action is GRANTED. The motion to disqualify Thomas J. Harlan, Jr., Esquire, and the law firm of Thomas J. Harlan and Associates is DENIED.

Mr. H. Leon Hodges, custodian of PSSI, shall promptly select new counsel and such new counsel shall promptly note an appearance with the Court.

The Clerk is DIRECTED to send a copy of this Order to counsel for the plaintiff and defendants.

Norfolk, Virginia

February 20, 1990
UNITED STATES OF AMERICA, Plaintiff-Appellant
(98-6609/6633)/Cross-Appellee, v. JOHN DAVID WHITE, Defendant-Appellee,
CAROLYN F. TAYLOR, Defendant-Appellee/Cross-Appellant (98-6634).

Nos. 98-6609/98-6633/98-6634

UNITED STATES COURT OF APPEALS FOR THE SIXTH CIRCUIT


June 21, 2000, Argued
October 29, 2001, Decided
October 29, 2001, Filed

PRIOR HISTORY: **[**1**]** Appeal from the United States District Court for the Western District of Kentucky at Owensboro. No. 97-00013. Joseph H. McKinley, Jr., District Judge.

DISPOSITION: Judgment as to Carolyn Taylor was affirmed. Sentencing order as to John White was vacated and remanded for resentencing.


Jennifer O. True, Nicholasville, Kentucky, Stewart B. Elliott, Owensboro, Kentucky, for Appellees.

ON BRIEF: Ronald M. Spritzer, UNITED STATES DEPARTMENT OF JUSTICE, Washington, D.C., Randy W. Ream, ASSISTANT UNITED STATES ATTORNEY, Louisville, Kentucky, for Appellant.

David Russell Marshall, Nicholasville, Kentucky, Stewart B. Elliott, Owensboro, Kentucky, for Appellees.

JUDGES: Before: KEITH, DAUGHTREY, and GILMAN, Circuit Judges.

OPINION BY: MARTHA CRAIG DAUGHTREY

OPINION

[***2] [***360] MARTHA CRAIG DAUGHTREY, Circuit Judge. Defendants John White and Carolyn Taylor, employees of the Ohio County (Kentucky) Water District, were convicted of making materially false statements regarding a matter within the jurisdiction of the federal government, in violation of 18 U.S.C. § 1001 (1994), by submitting [***2] reports containing falsified turbidity measurements to the Kentucky Division of Water. The district court sentenced White to two years' probation and a $5000 fine, and sentenced Taylor to two years' probation and a $1000 fine. The government now appeals the court's interpretation of the United States Sentencing Guidelines in determining White's and Taylor's sentences. Taylor cross-appeals, challenging both her sentence and various aspects of her prosecution. For the reasons set out below, we find no reversible error in connection with Taylor's conviction and sentence, and thus affirm that portion of the district court's judgment. We further hold, however, that the case must be remanded for re-sentencing as to White.

JUDICIAL BACKGROUND
John White was the general superintendent at the Ohio County Water District's drinking water treatment plant at Cromwell, Kentucky; Carolyn Taylor was a Water District employee assisting White in managing plant operations. Both were licensed by the state of Kentucky as Class 4A Water Treatment Plant Operators, which required multiple examinations and continuing education. As part of their job responsibilities, White and Taylor prepared monthly operations reports required by federal and state law to be submitted to the Kentucky Department for Environmental Protection's Division of Water. The Division of Water compiles this data from all the state's water districts as part of its enforcement responsibilities pursuant to the federal Safe Drinking Water Act, 42 U.S.C. §§ 300f-300j-18 (1994). The federal Environmental Protection Agency (EPA) funds the Division's data collection activities, and the Division sometimes works with EPA employees when investigating violations of the Act.

During a surprise inspection of the plant in January 1997, an agent from the Division noted that daily log books recording the measure of turbidity (the amount of suspended particulate matter in post-treatment water) had been left blank for each of four four-hour shifts between 4:00 p.m. January 13 and 8:00 a.m. January 14. The plant employee responsible for recording these measurements told the Division agent that she had purposefully left the log sheets blank because the turbidity measurements were all above 0.5 nephelometric turbidity units (NTUs), which might put the plant at risk of noncompliance with the Act.

In February 1997, however, White submitted a monthly report to the Division which contained entries below the 0.5 NTU threshold for each of the four-hour shifts in question. The Division then seized the Cromwell plant's daily log book and data sheets recorded by the plant's turbidimeters containing turbidity measurements for December 1996 and January 1997. Review of this evidence and subsequent interviews with plant staff, including White and Taylor, by Division and EPA agents revealed several instances of similar falsifications of turbidity measurements and submissions of inaccurate monthly reports, which suggested that the water plant had been out of compliance with the federal and state turbidity regulations during most of the months in question.

Under federal law, water districts using filtration systems to treat surface water are required to measure "grab samples" of the turbidity of treated drinking water every four hours, unless the state approves use of alternative continuous turbidity monitoring mechanisms. See 40 C.F.R. § 141.74(c)(1) (1999). Workers at the Ohio County plant were asked to take several "grab sample" measurements during each four-hour period and enter the lowest of these measurements in their daily logs.

Federal and Kentucky state regulations enforcing the Act require water districts to maintain treated water with less than 0.5 NTUs in 95 of all recorded measurements made each month. See 40 C.F.R. § 141.73(a)(1); 401 KY. ADMIN. REGS. 1:150 (2000). A public water system in Kentucky could thus submit no more than nine record entries above 0.5 NTUs, out of approximately 186 total entries each month, and still comply with the Act and its enforcing regulations. At no time may the turbidity level in grab samples exceed 5 NTUs. See 40 C.F.R. § 141.73(a)(2).

EPA employees investigating possible wrongdoing at the Cromwell plant shared this evidence with Assistant United States Attorneys for the Western District of Kentucky, who informed Taylor that she could be charged with violating 18 U.S.C. § 1001, but also said that she might qualify for pretrial diversion as an alternative to prosecution. Although Taylor volunteered to testify before the grand jury in hopes of gaining pretrial diversion, in October 1997 the grand jury indicted White, Taylor, and plant operator Brenda Glenn on four counts, alleging violations of § 1001, conspiring to violate § 1001, and obstruction of justice.

Except as otherwise provided in this section, whoever, in any matter within the jurisdiction of the executive, legislative, or judicial branch of the Government of the United States, knowingly and willfully--

(1) falsifies, conceals, or covers up by any trick, scheme, or device a material fact;


(2) makes any materially false, fictitious, or fraudulent statement or representation; or

(3) makes or uses any false writing or document knowing the same to contain any materially false, fictitious, or fraudulent statement or entry;

shall be fined under this title or imprisoned not more than 5 years, or both.


Prior to trial, Taylor and Glenn moved to suppress statements made in interviews with EPA and Division agents. The district court denied these motions. At trial, [**7] Taylor moved for a judgment of acquittal pursuant to Federal Rule of Criminal Procedure 29, arguing that the court lacked jurisdiction over her case because sanction of her conduct was a matter within the jurisdiction of the Division of Water and not within that of the EPA, and also that the government could not prove that any statements made by Taylor were materially false. The court denied these motions, holding that Taylor's conduct involved a matter within federal jurisdiction and reserving the issue of whether the statements were materially false for the jury to decide.

The jury found Glenn not guilty on all counts, but found White and Taylor guilty on the second count of the indictment, which charged that the defendants

each aided and abetted by the other, made and caused to be made a false material entry in that the defendants falsely entered turbidity readings onto the January Monthly Operating Report for the Ohio County Water District plant reflecting turbidity readings of less than .5 NTUS when in fact, as the defendants then and there knew, the true and correct turbidity readings were in excess of .5 NTUS.

[***6] agreement for diversion." The court denied this motion.

In his pre-sentence reports for White and Taylor, the federal probation officer handling their cases noted that the sentencing guideline ordinarily applicable to convictions pursuant to 18 U.S.C. § 1001 was § 2F1.1, entitled "Fraud and Deceit." The officer stated his belief, however, that sentencing the defendants under § 2Q1.3, entitled "Mishandling of Other Environmental Pollutants; Record Keeping, Tampering, and Falsification," was more appropriate, as was increasing both White's and Taylor's base offense level by four levels pursuant to § 2Q1.3(b)(1)(B) because their offense "involved a discharge, release, or emission of a pollutant," and further increasing White's sentence by two levels pursuant to § 3B1.3 because White had abused a position of public trust in committing his crime. The district court held that deciding whether to sentence White and Taylor pursuant to § 2F1.1 or § 2Q1.3 was unnecessary, on the grounds that both sections provided for a base offense level of six, and that the enhancement under § 2Q1.3(b)(1)(B) did not apply because turbidity in treated water was not a "pollutant" that was released into the environment. The court also increased both White's and Taylor's sentence by two levels pursuant to § 3B1.3 because White had abused a position of public trust in committing his crime. The court's use of the "special skill" enhancement precluded the government's suggested use of § 3Bi.1(c) to increase White's sentence by two more levels as the alleged "organizer, leader, manager, or supervisor in . . . criminal activity," because under the guidelines, such an enhancement could not be used in addition to a § 3B1.3 "special skill" enhancement. Following its determination of the appropriate guidelines, the court sentenced White to two years' probation, including six months' home detention, and a $5,000 fine, and sentenced Taylor to two years' probation, including three months' home detention, and a $1,000 fine.

[**10] [***7] The government now appeals from the court's sentencing order, arguing that the district court should have used guideline § 2Q1.3 as a basis for White's and Taylor's sentences, and then applied a "release of pollutant" enhancement pursuant to § 2Q1.3(b)(1). The government also argues that the court should have used both the § 3B1.3 "abuse of trust" and § 3Bi.1(c)
"criminal supervisor" enhancements to increase White's sentence. Taylor cross-appeals from the final judgment against her, challenging the court's determination that her case involved a matter within the jurisdiction of the federal government. She also challenges the court's denials of her motion to suppress, her motion claiming that, as a matter of law, her statements were not materially false, and her motion seeking enforcement of the government's offer of pretrial diversion. Finally, she also appeals the court's use of the "special skill" enhancement in determining her sentence.

DISCUSSION

I. Taylor Conviction Issues

A. Jurisdiction

Taylor first argues that the district court erred in determining that her alleged false statements, the inaccurate turbidity readings in the January 1997 [**11] Monthly Operating [*363] Report, pertained to a matter within the jurisdiction of a federal agency. Whether the district court correctly decided this jurisdictional matter is a question of law that this court reviews de novo. See United States v. Shafer, 199 F.3d 826, 828 (6th Cir. 1999).

18 U.S.C. § 1001 criminalizes the willful making of materially false statements "in any matter within the jurisdiction of the executive, legislative, or judicial branch of the Government of the United States." The primary purpose of this jurisdictional requirement is "to identify the factor that makes the false statement an appropriate subject for federal concern." United States v. Yermian, 468 U.S. 63, 68, 82 L. Ed. 2d 53, 104 S. Ct. 2936 (1984). The Supreme Court has stated that the term "jurisdiction" [***8] here should not be given a "narrow or technical meaning" for purposes of § 1001. See Bryson v. United States, 396 U.S. 64, 70, 24 L. Ed. 2d 264, 90 S. Ct. 355 (1969). Instead, courts should apply the most natural, nontechnical reading of the statutory language . . . that it covers all matters confided to [**12] the authority of an agency or department. . . . A department or agency has jurisdiction, in this sense, when it has the power to exercise authority in a particular situation. Understood in this way, the phrase 'within the jurisdiction' merely differentiates the official, authorized functions of an agency or department from matters peripheral to the business of that body.


In distinguishing whether allegedly false statements made, as in this case, to state or municipal agencies or private entities related to "official" or "authorized" federal agency functions, rather than "peripheral" matters, we have in the past looked to whether the entity to which the statements were made received federal support and/or was subject to federal regulation. See Shafer, 199 F.3d at 828-29 (discussing United States v. Gibson, 881 F.2d 318, 322 (6th Cir. 1989), and United States v. Lewis, 587 F.2d 854, 855-57 (6th Cir. 1978)). In this case, the Division of Water, the recipient of Taylor's statement, reviews the turbidity [**13] data sent to it by all public water systems in the state that treat drinking water for human consumption pursuant to federal and state regulations. The Division applies each year for federal funding in order to administer their review and compliance programs; in fiscal year 1997, the Division received over $ 800,000 from the EPA. The EPA then audits the Division's programs to determine whether the Division is accurately monitoring compliance with federal regulations. The funding itself underscores the EPA's interest in monitoring these systems. Furthermore, although the Division has primary enforcement authority pursuant to the Safe Drinking Water Act over noncompliant local water systems, the Division enforces state [***9] regulations which are required to be no less stringent than those regulations promulgated by the federal government. See 40 C.F.R. § 142.10. Should the Division fail to monitor local water systems properly and enforce compliance with the regulations, the EPA also has statutory enforcement authority. See 42 U.S.C. § 300g-3(a), (b), (g) (West 1999) (granting EPA Administrator authority to issue civil [**14] compliance order or commence civil action should the state with primary enforcement authority fail to commence appropriate enforcement action); 42 U.S.C. § 300l(a), (b) (granting Administrator authority to issue orders or commence civil actions where "imminent and substantial endangerment" to public health exists); [**364] 42 U.S.C. § 300j-4(b) (authorizing Administrator or her representatives to enter drinking water treatment plants to ascertain compliance with national drinking water regulations). The government presented uncontroverted
testimony at trial that the EPA exercised its enforcement authority, at the behest of Division of Water officials, with regard to several noncompliant local water systems in Kentucky. These federal enforcement actions, although perhaps secondary to those by states, like Kentucky, with primary enforcement authority, evince a federal interest in what reasonably must be considered an official function of the EPA, ensuring safe drinking water for all persons residing in the United States. We therefore hold that the false statements made to the Division regarding drinking water turbidity levels came within the jurisdiction of the EPA for purposes of prosecution under § 1001.

We are not the only court to so hold. In United States v. Wright, 988 F.2d 1036 (10th Cir. 1993), the Tenth Circuit reached a similar conclusion. As superintendent of a drinking water treatment plant in Sequoyah County, Oklahoma, Wright filed false turbidity reports with the county's health department. See Wright, 988 F.2d at 1037. He moved unsuccessfully in district court to dismiss the indictment against him that alleged a violation of § 1001. See id. In affirming the district court's denial of the motion to dismiss, the court stated:

The false turbidity data filed by Mr. Wright fell within the jurisdiction of the EPA. A grant of primary authority is not a grant of public authority. . . . The Act requires the Administrator to promulgate maximum contaminant level goals and national primary drinking water regulations. The regulations relating to the collection and reporting of turbidity data, described above, were promulgated pursuant to that charge and authority. The EPA retains the authority, in the discharge of its duties under the Act, to enforce its regulations; and, turbidity data clearly concern an authorized function of the EPA.

Furthermore, in this situation, the EPA is actively involved in assuring state compliance with national safe water standards. It audits, reviews, and evaluates the state of Oklahoma's program, including an inspection of the monthly reports of the type involved in this case. Such reports, therefore, directly implicate the ongoing function and mission of the agency. In addition, the Act expressly authorizes the EPA to take enforcement actions in states having primary enforcement authority.

Finally, EPA's funding of the Oklahoma public water program is conditioned, in part, on the results of its annual evaluations of that program. This court is in accord with other circuits which have found that a state agency's use of federal funds, standing alone, is generally sufficient to establish jurisdiction under section 1001.

988 F.2d at 1038-39 (citations omitted). Although our case law appears to require more than the mere expenditure of funds to establish jurisdiction pursuant to § 1001, see United States v. Holmes, 111 F.3d 463, 465-66 (6th Cir. 1997), the combination of reasons given by the Wright court for its holding persuades us that federal jurisdiction is appropriate in this case as well. Taylor's attempts to distinguish her case from Wright, by contending that Kentucky has exclusive enforcement authority over local water systems and that the EPA was not funding the Division's record-keeping programs, are factually inaccurate and thus do not provide a basis for finding a lack of jurisdiction here.

[*365] B. Materiality

Perhaps because "there can be no valid conviction under § 1001 'unless both jurisdiction and materiality are shown,'" United States v. Rutgard, 116 F.3d 1270, 1287 (9th Cir. 1997) (quoting United States v. Facchini, 874 F.2d 638, 641 (9th Cir. 1989) (en banc)), Taylor next questions whether the evidence presented at trial sufficiently proved that her alleged false statements were "material" for purposes of § 1001. As with other sufficiency-of-the-evidence questions, we determine whether evidence sufficiently supported a § 1001 conviction by deciding "whether, after viewing the evidence in the light most favorable to the government, any rational trier of fact could have found the elements of the crime beyond a reasonable doubt." United States v. Gatewood, 173 F.3d 983, 986 (6th Cir. 1999) (citing Jackson v. Virginia, 443 U.S. 307, 319, 61 L. Ed. 2d 560, 99 S. Ct. 2781 (1979)).
A showing of "materiality" is a fairly low bar for the government to meet: a statement is "material" in this context if it has the natural tendency to influence or is capable of influencing a federal agency. See United States v. Lutz, 154 F.3d 581, 588 (6th Cir. 1998). A showing of actual influence, or actual agency reliance, is unnecessary, see United States v. Keefer, 799 F.2d 1115, 1128 (6th Cir. 1986); indeed, "there is no implicit requirement that the [false] statements be made directly to, or even received by, the federal department or agency." Lutz, 154 F.3d at 587 (quoting Gibson, 881 F.2d at 322). If the false statements are received by an agency, they may be material even if the receiving agent or agency knows that they are false. See United States v. Rogers, 118 F.3d 466, 472 (6th Cir. 1997).

Still, the [**19] fact that materiality is a low hurdle does not mean that it is no hurdle; the government must present at least some evidence showing how the false statement in question was capable of influencing federal functioning. In this case, we conclude, the government presented enough "circumstantial" [***12] evidence of how the false statements could have affected EPA functioning--apart from Taylor's prosecution under § 1001 itself--to support her conviction. Both EPA agent Libby Haines and FBI agent Wayne McAllister testified that they investigated the Ohio County plant at the behest of the Division. Vicki Ray, the manager of the drinking water branch of the Division of Water, testified that the Division had turned over several local drinking water systems with reporting violations to the EPA for "federal enforcement." Ray also described what "enforcement" of the regulations means: noncompliant local water systems receive notification of a violation and then are required to correct the problem, and are told to notify their customers regarding violations by newspaper announcement and, if necessary, by direct mail or through radio and television advertisements. Ray's description dovetails [**20] with the procedures stated in and mandated by federal drinking water regulations, see 40 C.F.R. § 141.32, which, as discussed above, the EPA regularly carries out, with or without state cooperation. Through the testimony of Haines, McAllister, and Ray, the jury could have found that the false statements in the Ohio County plant's monthly report, if discovered, had the capacity to affect the EPA's administrative enforcement of the drinking water regulations.

Taylor argues that because the regulations allow up to nine record entries, or 5% of the total entries for the month, to be above 0.5 NTUs before a water system's monthly report would be flagged for noncompliance and/or possible enforcement action, the four false entries in the January [*366] 1997 report should not have been found to be material. This argument ignores the fact that the false entries, even if not violations in and of themselves, when discovered could and did lead to the seizure of other plant records which demonstrated more severe instances of noncompliance over a longer period of time, all of which was documented at trial. Because Taylor's statements influenced the course of an investigation, [**21] which, apparently, still could result in an agency enforcement action, they were materially false for purposes of her prosecution.

[***13] C. Suppression of Taylor's Statements

Taylor next appeals the district court's denial of her motion to suppress, arguing that inculpatory statements she made in a May 21, 1997 interview with agents Haines and McAllister in her home should be suppressed as violative of her Fifth Amendment right against self-incrimination. 4 We review a district court's findings of fact regarding a suppression motion for clear error, and its related conclusions of law de novo. See United States v. Bencs, 28 F.3d 555, 558-59 (6th Cir. 1994).

4 Taylor's appeal brief also seeks suppression of statements made on July 9, 1997. Her motion to suppress in the district court, however, does not mention these statements or identify how their admission into evidence would violate her constitutional rights. As a general rule, we do not review suppression issues raised for the first time on appeal. See United States v. Critton, 43 F.3d 1089, 1093-94 (6th Cir. 1995).

[**22] In its order denying Taylor's suppression motion, the district court made the following factual findings:

The Court finds that Special Agent Haines and Special Agent McAllister traveled to Defendant's residence in Ohio County on May 21, 1997. The Agents introduced themselves to Taylor, showed their identification, and told her they were conducting an investigation into false statements on turbidity reports submitted by the plant for whom she worked. . . . Taylor consented to be interviewed in her
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against you is under consideration for pretrial diversion” and that it “has been referred to the United States Attorney that a defendant will not be indicted by a government employee other than the United States Attorney unless breach of such an agreement resulted in a fundamentally unfair prosecution, a circumstance not present here. See United States v. Crowell, 987 F.2d 368, 373 (6th Cir. 1993). [**24]

Taylor also claims that Assistant United States Attorney Randy Ream similarly promised her pretrial diversion in a letter dated June 18, 1997. The letter from Ream to Taylor, however, states only that “the case against you is under consideration for pretrial diversion” and that it "has been referred to the United States Probation Office for a recommendation as to whether you can be placed on pretrial diversion.” (Emphasis added.) Regardless of Taylor's subjective belief as to what Ream stated, the language in the June 18 letter supports the government's contention that, judged objectively, Ream made no offer of pretrial diversion to Taylor and, therefore, that the district court could not have enforced the agreement Taylor now alleges existed. Nor does [***15] Taylor point to evidence that she reasonably relied to her detriment on any promise she believed the government may have made. We thus conclude that the district court did not err in refusing to dismiss Taylor's indictment or order her participation in pretrial diversion.

II. Sentencing Issues

A. Base Offense Level and "Release of Pollutant" Enhancement

The government challenges the district court's [**25] decision to set both White's and Taylor's base offense levels at six without choosing between § 2F1.1, the guideline generally applicable to violations of 18 U.S.C. § 1001, and § 2Q1.3, a guideline pertaining to the reporting of false environmental data to government authorities. [5] The government also argues that the district court erred in holding that enhancement pursuant to § 2Q1.3(b)(1) was inappropriate because the offense for which White and Taylor were convicted did not result in or otherwise involve a discharge, release or emission of a pollutant into the environment. In reviewing a district court's sentencing decision pursuant to the guidelines, we review all determinations of fact for clear error, and we review the court's application of the guidelines to the facts de novo. See United States v. Waldon, 206 F.3d 597. 608 (6th Cir.), cert. denied, 531 U.S. 881, 148 L. Ed. 2d 134, 121 S. Ct. 193 (2000). The government must prove all facts used in sentencing determinations by a [***16] preponderance of the evidence. See United States v. Crowell, 997 F.2d 146, 149 (6th Cir. 1993).

[5] The Statutory Index to the Sentencing Guidelines specifies § 2F1.1 as the guideline "ordinarily applicable" to convictions pursuant to 18 U.S.C. § 1001. See U.S. Sentencing guidelines Manual, Appendix A (1997). The Index also states, however, that "if, in an atypical case, the guideline section indicated for the statute of conviction is inappropriate because of the particular conduct involved, use the guideline section most applicable to the nature of the
offense conduct charged in the count of which the defendant was convicted. Id. The commentary to § 2F1.1 itself also suggests considering use of another guideline if more appropriate to the defendant's charged conduct. See U.S. Sentencing guidelines Manual, § 2F1.1 cmt. n.13 (1990).

[**26] In setting White's and Taylor's base offense level at six, the district court held that choosing between § 2F1.1 and § 2Q1.3 was unnecessary because the sentence enhancements available at § 2Q1.3(b)(1), potentially increasing the defendants' sentences by four or six levels, did not apply. The court stated:

The Court finds that in the present case turbid water cannot be considered a pollutant. [*368] Turbidity has been defined simply as a measure of water clarity or a measure of particles in the water. The Government cites no case law, statute, or regulation in support of its argument that turbidity is a pollutant under § 2Q1.3(b)(1)(A). Instead, the only argument the Government makes is that when the turbidity readings are above .5 NTUs, the risk of there being harmful bacteria in the drinking water increases. This alone is insufficient. The water leaving the plant was cleaner than the water coming into the plant. It just wasn’t clean enough. However, there is no evidence in the record that a pollutant was discharged into the environment. Therefore, the Court finds that no increase is warranted . . . .

In response to the court’s challenge regarding legal support for its [*27] enhancement claim, the government on appeal cites to the Safe Drinking Water Act and its enforcing regulations defining "turbidity," not as a "pollutant," but rather as a "contaminant," and then claims that for sentencing purposes the two concepts should be seen as substantive equivalents. The government’s argument may be summarized as follows: The Act defines the term "contaminant" as "any physical, chemical, biological, or radiological substance or matter in water." 42 U.S.C. § 300f(f). Regulations enforcing the Act set maximum drinking water contaminant levels for turbidity separate from those for any other regulated contaminant, see 40 C.F.R. § 141.13, distinguish turbidity from other contaminants in a number of other respects, see 40 C.F.R. § 141.70(a); [***17] 40 C.F.R. Ch. 1, Subpt. O, App. C; 40 C.F.R. § 141.153(d)(4)(v), and thus appear to indicate the EPA’s intent that turbidity be considered a "contaminant" for regulatory purposes.

The government also notes that the plain meaning of the terms "contaminate" and "pollute" are, for the most part, synonymous, [**28] and therefore argues that turbidity reasonably may be called a pollutant. Webster's Dictionary defines "contaminate" as "to soil, stain, or infect by contact or association," and lists as a "sometimes interchangeable" synonym the term "pollute." Webster's New Collegiate Dictionary 245 (1975). "Pollute" is defined as "to make physically impure or unclean . . . to contaminate (an environment)." Id. at 891. As the government points out, nothing in guideline § 2Q1.3 suggests construing the term "pollutant" more narrowly for federal sentencing purposes; in fact, the commentary to the guideline indicates just the opposite, stating that "a wide range of conduct, involving the handling of different quantities of materials with widely differing propensities, potentially is covered" by § 2Q1.3(b)(1). U.S. Sentencing guidelines Manual § 2Q1.3 cmt. n.4 (1997). Finally, the government cites language from the Clean Water Act, another federal statute targeting the safety of the national water supply. That act defines the term "pollutant" as "dredged spoil, solid waste, incinerator residue, sewage, garbage, sewage sludge, munitions, chemical wastes, biological materials, radioactive [**29] materials, heat, wrecked or discarded equipment, rock, sand, cellar dirt and industrial, municipal, and agricultural waste discharged into water," 33 U.S.C. § 1362(6) (emphasis added), a description that appears to include turbidity.

We appreciate the logic in the government’s position. Furthermore, we note that other courts have, implicitly if not explicitly, recognized over-turbidity as at least a regulatory proxy for pollutants in various legal contexts. See, e.g., Florida Rock Indus., Inc. v. United States, 791 F.2d 893, 895-96 (Fed. Cir. 1986) (referring [*369] to turbidity as "water pollution"); Stoddard v. W. Carolina Reg'l Sewer Auth., 784 F.2d 1200, 1203, 1207 [***18] (4th Cir. 1986) (recognizing that measures of "suspended solids" in water, although not pollutants, indicated presence of pollutants and that violations of permits regulating such measurements issued pursuant to Clean Water Act caused significant long-term environmental

But even were we to join our sister circuits in holding that over-turbidity is a "pollutant" for purposes of § 2Q1.3, such a holding would not mean that the enhancements stated in § 2Q1.3(b)(1) should apply to White's and Taylor's sentences. We believe that ultimately the regulatory character of the Safe Drinking Water Act and the language and structure of the sentencing guidelines as a whole preclude the use of the enhancements the government seeks. The background to the commentary to § 2Q1.3, which applies to conduct involving the mishandling of nonhazardous substances and/or related record-keeping offenses, states that the section parallels § 2Q1.2, involving the mishandling of pesticides and other toxic or hazardous substances. See U.S. Sentencing guidelines Manual § 2Q1.3 cmt. background (1997). *Section 2Q1.2(b)* contains six subsections detailing "specific offense characteristics" enhancing a defendant's base offense level; the first of these [*331] is the parallel to § 2Q1.3(b)(1), the "release of pollutant" enhancement at issue here. The background to the commentary to § 2Q1.2 states that "the first four specific offense characteristics provide enhancements when the offense involves a substantive violation. The last two specific offense characteristics apply to record-keeping offenses." U.S. Sentencing guidelines Manual § 2Q1.2 cmt. background (1997). *Section 2Q1.2(b)(5)*, one of the "last two" enhancements referred to in the commentary and precisely paralleled by § 2Q1.3(b)(5), states that "if a record-keeping offense reflects an effort to conceal a substantive environmental offense, use the offense [*331] level for the substantive offense." Although the commentary to § 2Q1.3 does not include a limiting rule similar to that in § 2Q1.2, we infer that § 2Q1.3(b)(5) is the only enhancement in the guideline that applies to "record-keeping offenses."

In seeking enhancements under § 2Q1.3(b)(5) for White's and Taylor's convictions pursuant to 18 U.S.C. § 1001, the government apparently asks us to accept § 1001 as a "record-keeping offense." Regardless of whether the defendants' § 1001 convictions [*332] should be considered "record-keeping offenses," however, neither the Safe Drinking Water Act nor any other federal statute contains a "substantive environmental offense" criminalizing the defendants' conduct, even if that conduct is thought to include allowing the release of contaminated water into the environment. The defendants' purported record-keeping offenses thus do not -- indeed, cannot -- reflect an effort to conceal a substantive environmental offense, because no federal statute criminalizes the regulatory violations underlying the defendants' fraudulent conduct. [*330] We also see [*332] no way in which the § 1001 offenses themselves [*332] could be considered substantive environmental offenses. We therefore conclude that the language in the separate provisions of and commentaries to § 2Q1.2 and § 2Q1.3, which appear to limit use of "release of pollutant" enhancements to convictions pursuant to substantive criminal environmental offenses or the record-keeping offenses concealing them, prevents the use of the § 2Q1.3(b)(1) enhancements the government argues are appropriate here.

*6* The Safe Drinking Water Act differs from the statutes specifically covered by guideline § 2Q1.3 on this point. See 42 U.S.C. §§ 300f-300q-18 (provisions of Safe Drinking Water Act); cf. 33 U.S.C. § 1319(c) (criminal conduct provisions of Clean Water Act); 33 U.S.C. § 1415(b) (criminal conduct provisions of Marine Protection, Research, and Sanctuaries Act); 33 U.S.C. §§ 1907, 1908 (criminal conduct provisions of Act to Prevent Pollution from Ships); 42 U.S.C. § 7413 (criminal conduct provisions of Clean Air Act). The Safe Drinking Water Act and accompanying regulations accomplish federal enforcement of the Act, when necessary, primarily by administrative order or civil action. See 42 U.S.C. § 300g-3 (civil and administrative enforcement of drinking water regulations). The Act contains two provisions criminalizing conduct relating to the provision of safe drinking water: § 300h-2, which prohibits willful violations of state laws regulating underground injection control programs, and § 300i-1, which prohibits tampering, attempted tampering, or threatened tampering with a public water system with the intention of harming persons. See 42 U.S.C. § 300i-1. Separate guideline provisions, § 2Q1.2, § 2Q1.4, and § 2Q1.5 cover punishments for convictions pursuant to these sections of the Act. Because the defendants here were not convicted of violating...
either § 300h-2 or § 300l-1 and their proven conduct was not prohibited by either statute, the government acknowledges that these sections do not apply.

[**33] In sum, even if turbidity is considered a "pollutant" for purposes of § 2Q1.3(b)(1), the district court did not err in refusing to enhance White's and Taylor's sentences pursuant to this guideline provision because their "record-keeping offense" cannot be said to reflect an effort to conceal a "substantive environmental offense" under the Safe Drinking Water Act or any other federal statute. The only substantive offense involved in this case was the violation of § 1001; under either § 2F1.1 or § 2Q1.3, if applied, the defendants' base offense level for this criminal conduct would be six. We therefore hold that the district court did not err in finding that the sentencing calculation under either guideline would be the same.

B. "Abuse of Trust" Enhancement

The district court enhanced both White's and Taylor's sentences pursuant to guideline § 3B1.3, because it found that both defendants used a special skill in committing their § 1001 fraud offenses. Section 3B1.3 states:

If the defendant abused a position of public or private trust, or used a special skill, in a manner that significantly facilitated the commission or concealment of the offense, increase by 2 levels. [**34] This adjustment may not be employed if an abuse of trust or skill is included in the base offense level or specific offense characteristic. If this adjustment is based on an abuse of a position of trust, it may be employed in addition to an adjustment under § 3B1.1 (Aggravating Role); if this adjustment is based solely on the use of a special skill, it may not be [***21] employed in addition to an adjustment under § 3B1.1 (Aggravating Role).

The government challenges the court's rationale for its § 3B1.3 enhancement of White's sentence, claiming, as it did at trial, that White's sentence should have been adjusted because he abused a position of public or private trust in committing his offense; a reversal on this point would allow the government to seek an additional upward adjustment pursuant to § 3B1.1 for White's alleged aggravating role as an organizer, leader, manager, or [*371] supervisor of criminal activity at the plant. We review a district court's "abuse of trust" determination de novo. See United States v. Tribble, 206 F. 3d 634, 635 (6th Cir. 2000).

In analyzing claims that an abuse-of-trust enhancement should apply to a criminal defendant's sentence, [**35] this court has necessarily identified whether the defendant held a position of trust, and whether the position of trust facilitated the commission of the crime. See, e.g., United States v. Talley, 194 F. 3d 758, 766 (6th Cir. 1999), cert. denied, 528 U.S. 1180, 114 L. Ed. 2d 3118, 120 S. Ct. 1217 (2000). The heart of the dispute between the parties here involves what is arguably a threshold question, however: the identity of White's victims. The abuse-of-trust enhancement may only be applied where the defendant abused a position of trust with the victim of his charged conduct. See United States v. Moored, 997 F. 2d 139, 145 (6th Cir. 1993).

White, following the district court, argues that his victims were the EPA and the Division of Water, the government agencies to which he was required to report turbidity levels. The government claims that the residents of Ohio County who received drinking water treated at the facility White managed were also victims of White's conduct. In so doing, the government echoes the opinions of numerous courts that have, when deciding whether to enhance a government employee defendant's sentence [**36] pursuant to § 3B1.3, appeared to treat the general public as victims of the employee's conduct, in place of or in addition to the government agency or agencies they served. See, e.g., United States v. Robinson, 339 U.S. App. D.C. 226, 198 F.3d 973, 978 (D.C. Cir. 2000) ("Because Robinson was the founder and director of the [public] school, he gained the public trust of the community that [the school] served."); United States v. Brown, 7 F.3d 1155, 1161 (5th Cir. 1993) ("It is axiomatic that the public places tremendous trust in prison employees that they will not conspire with inmates to violate the law."); United States v. Lamb, 6 F.3d 415, 421 (7th Cir. 1993) ("Police officers are accorded public trust to enforce the law. The public . . . expects that police officers will not violate the laws they are charged with enforcing.").

We have not, in the past, expressly held that the general public could be considered a victim of a
government employee's crime, although we have decided, without explanation, cases in which the "general public as victim" theory could have applied that the § 3B1.3 [***37] enhancement did apply. See Talley, 194 F.3d at 766 (holding that lieutenant in sheriff's office abused position of public trust); United States v. Blandford, 33 F.3d 685 (6th Cir. 1994) (finding no error in application of abuse-of-trust enhancement to sentence of speaker of Kentucky House of Representatives convicted under RICO of misuse of campaign funds); United States v. Sivils, 960 F.2d 587, 599 (6th Cir. 1992) (holding that enhancement applied to deputy sheriff's conviction and sentence). We believe that our failure to so hold was because it is, or should be, self-evident that an enhancement for abuse of "position of public or private trust," U.S.S.G. § 3B1.3 (emphasis added), may be appropriate when the public has been victimized by the defendant's crime. Should any confusion remain on this point, we now explicitly hold that the general public as victims of a government employee's crimes for purposes of deciding whether the employee's sentence may be enhanced pursuant to § 3B1.3. This is not the end of our analysis, however. We must decide whether White held a position of trust vis a vis the water district [***38] customers, and whether his charged conduct violated that trust.

[***37] To do so, we must turn to application note 1 to the commentary to § 3B1.3, which states: [***23]

"Public or private trust" refers to a position of public or private trust characterized by professional or managerial discretion (i.e., substantial discretionary judgment that is ordinarily given considerable deference). Persons holding such positions ordinarily are subject to significantly less supervision than employees whose responsibilities are primarily non-discretionary in nature. For this adjustment to apply, the position of public or private trust must have contributed in some significant way to facilitating the commission or concealment of the offense (e.g., by making the detection of the offense or the defendant's responsibility for the offense more difficult). This adjustment, for example, applies in the case of an embezzlement of a client's funds by an attorney serving as a guardian, a bank executive's fraudulent loan scheme, or the criminal sexual abuse of a patient by a physician under the guise of an examination. This adjustment does not apply in the case of an embezzlement or theft by an ordinary [***39] bank teller or hotel clerk because such positions are not characterized by the above-described factors.

Notably, the commentary fails, in its efforts to define the term "public or private trust," to include among its examples of positions of trust--an attorney's embezzlement of a client's funds, a bank executive's fraud scheme, and a physician's abuse of a patient--a scenario in which a defendant enjoys a trust relationship with the general public. Instead, the commentary emphasizes the "substantial discretionary judgment" awarded to the defendant in a position of trust for purposes of § 3B1.3. See U.S. Sentencing guidelines Manual § 3B1.3 cmt. n.1 (1997); see also Tribble, 206 F.3d at 637 (stating that "according to our own precedent, and to the application notes . . . the level of discretion accorded an employee is to be the decisive factor" and, continuing, "the inherent nature of the work itself should naturally convey a substantial degree of discretion to the defendant concerning how to properly administer the property of another or otherwise act in their best interest"). Indeed, based on its reading of this commentary, this court has held that [***40] the phrase [***24] "position of public or private trust" is a term of art, "appropriating some of the aspects of the legal concept of a trustee or fiduciary," and not an approximation of "the ordinary dictionary concept of reliance or confidence." United States v. Ragland, 72 F.3d 500, 502-03 (6th Cir. 1996).

We do not believe that all members of the general public share such a quasi-fiduciary relationship with all public servants. It seems impossible that the sentencing commission intended that every "faceless" government bureaucrat performing her duties with some measure of discretion should be subject to an abuse-of-trust enhancement should she be convicted of any crime. White urges, as a limiting principle, that only elected officials should be considered to enjoy a trust relationship with the voting public making the enhancement appropriate. We disagree. In this case, it is obvious that customers of the Water District placed a high degree of trust in the District to provide them with potable drinking

water, and granted the District substantial discretion, subject to federal and state regulation, as to how to provide such a service. The District, in turn, [*372] placed White in charge of its water purification efforts with apparently little or no administrative oversight; indeed, it appears that White's misdeeds would never have been discovered had there not been a surprise inspection by Division of Water [*373] agents. Given these facts, we believe that the quasi-fiduciary trust relationship between the District and its customers should be imputed to White, and thus that the abuse-of-trust enhancement was appropriate here given his violation of the public trust. Such a result appears to comport with the example from the guideline commentary of the bank executive who perpetrates fraud upon the bank's customers, many if not all of whom may not necessarily have known the executive's identity but engaged in a trust relationship with the bank and its administrative personnel nonetheless. This result also follows the apparent reasoning of our sister circuits that officers charged with protecting public health and safety, whether or not elected by or known to members of the public, enjoy a special trust relationship with the public that is [*374] breached when they commit a crime. See, e.g., Brown, 7 F.3d at 1161; Lamb, 6 F.3d at 421. [*42] It follows that the district court erred in reaching an opposite conclusion; on remand, the court should both correct this error and consider the propriety of also enhancing White's sentence pursuant to § 3B1.1.

C. "Special Skill" Enhancement

Finally, Carolyn Taylor contests the district court's decision to enhance her sentence pursuant to § 3B1.3 because she used a special skill "in a manner that significantly facilitated the commission or concealment of [her] offense." We review such factual findings made as part of a § 3B1.3 enhancement determination for clear error. See United States v. Lewis, 156 F.3d 656, 658 (6th Cir. 1998) (quoting United States v. Atkin, 107 F.3d 1213, 1219 (6th Cir. 1997)).

In holding that Taylor used a special skill, the district court specially noted the fact that Taylor possessed a 4A Water Treatment Plant Operators' License. Taylor argues that her license is not evidence of a special skill because performing turbidity tests does not require certification, and because at the Ohio County plant such tests were regularly performed by unlicensed operators. The commentary to § 3B1.3 defines a "special skill" [*43] as "a skill not possessed by members of the general public and usually requiring substantial education, training, or licensing," and lists as examples of persons with special skills pilots, lawyers, doctors, accountants, chemists, and demolition experts. See U.S. Sentencing guidelines Manual § 3B1.3 cmt. n.2 (1997). The district court found that, as a licensed plant operator, defendant Taylor possessed such skills and further found that her skills "significantly facilitated the commission or concealment of the offense." A majority of the panel concludes that the district judge did not clearly err in making these findings. [*26] 7 The guidelines test was [*26] met in this case because Taylor's training and experience in water treatment plant operation made it significantly easier for her to falsify turbidity readings and to conceal the falsifications from the regulators. The Class 4A water treatment plant operator's license that Taylor held is the highest category operator's license that the state confers. It requires annual training, educational courses, and completion of an examination. While the actual entry of the numbers requires no particular skill, Taylor had to make certain [*44] calculations that took into account prior turbidity rates, temperature, chemical feed rates, etc., in order to reconstruct [*374] turbidity measurements that would have at least a superficial plausibility and thereby conceal the falsifications. Hence, the defendant's argument that two other operators also recorded turbidity measurements is not persuasive, given the fact that she has not shown that they would have been capable of committing and concealing the offense in the manner that she did.

7 Judge Daughtrey disagrees and would reverse the district court's determination and remand for resentencing on the basis of the court's analysis in United States v. Weinstock, 153 F.3d 272, 281 (6th Cir. 1998)(podiatric skills did not facilitate podiatrist's crime involving false billing).

CONCLUSION

For the reasons set out above, we AFFIRM the judgment of the district court as to Carolyn Taylor, but VACATE the sentencing order as to John White and REMAND for resentencing in conformity with [*45] this opinion.
Duty/Obligation When Attorneys Learn After Settlement That Plaintiff's Expert Witness Lied About His Qualifications in Depositions.

September 8, 1995

You have presented a hypothetical situation in which the plaintiff's expert lies about his credentials during his deposition. The false credentials of this expert form the basis of his expert opinion. Counsel for plaintiff uses this expert opinion to negotiate a six-figure settlement. Subsequently, attorneys for both sides learn that the expert witness lied about the professional qualifications that formed the basis of his expert opinion.

Under the facts you have presented, you have asked the committee to opine as to the obligations of counsel once they became aware of the expert witness' perjury.

The appropriate and controlling disciplinary rule relative to your inquiry is DR:7-102(B)(1) which states that a lawyer who receives information clearly establishing that a person other than his client has perpetrated a fraud upon a tribunal shall promptly reveal the fraud to the tribunal (emphasis added). The committee has previously opined that false testimony given by a client during a deposition may constitute a “fraud upon a tribunal,” adopting the view of other jurisdictions which have implicitly included depositions within the definition of “tribunal.” LE Op. 1451.

The committee also stated that the false testimony must be examined to determine whether disclosure is required “to prevent a judgment from being corrupted by the [witness's] unlawful conduct.” Id. Thus, not every misrepresentation made by a witness in a deposition is a “fraud upon the tribunal.”

Assuming that the plaintiff's expert's qualifications about which he lied are material to the opinion rendered by such expert, the committee believes that it would be improper to allow the false deposition testimony to stand, regardless of whether the case proceeds to trial or is settled.

In the facts you present, the committee believes that if the expert's perjured testimony is so material to the opinion given by such expert that it corrupts the opinion, then counsel is required under DR:7-102(B)(1) to reveal the fraud to the tribunal.

Committee Opinion September 8, 1995

Zealous Representation: Conducting Settlement Negotiations Based on Unamended Answers to Interrogatories

You have presented a hypothetical situation in which an attorney represents a client in products liability litigation. The client's answers to interrogatories were believed to be accurate when signed under oath. Subsequently, however, the attorney learns the answers are incorrect and, under Rule 4:1(E)(2) of the Rules of the Supreme Court of Virginia, the answers will have to be seasonably amended. The client, however, wishes to attempt a settlement before amending interrogatory answers or otherwise disclosing the correct facts, which disclosure will adversely affect the settlement value of the case.

You have asked the committee to opine whether, under the facts of the inquiry, (1) the attorney may attempt a settlement without first amending the incorrect interrogatory answers, and (2) whether the attorney is permitted to enter settlement negotiations as long as he does not verbally reaffirm the incorrect interrogatory answers, but rather remains silent.

The appropriate and controlling Disciplinary Rules related to your inquiry are DR 1-102(A)(4) which states that a lawyer shall not engage in conduct involving dishonesty, fraud, deceit or misrepresentation which reflects adversely on his fitness to practice law; DR 7-102(A)(3), (5), (6), and (7) which provide, respectively, that a lawyer shall not conceal or knowingly fail to disclose that which he is required by law to reveal; knowingly make a false statement of law or fact; participate in the creation or preservation of evidence when he knows or it is obvious that the evidence is false; or counsel or assist his client in conduct that the lawyer knows to be illegal or fraudulent.

The facts you provide indicate that the answers were signed under oath and that the attorney has knowledge that the answers are inaccurate. The committee opines that it would be improper and violative of DRs 1-102(A)(4), 7-102(A)(5), (6), and (7) for the attorney to attempt a settlement without first amending the incorrect interrogatory answers. The committee further opines that because the attorney is obligated under the Rules of the Supreme Court of Virginia to seasonably amend the incorrect interrogatory answers, any attempt to settle before such amendment would also be violative of DR 7-102(A)(3). See LEO #743.

With regard to your second inquiry, the committee is of the opinion that it would be improper and violative of the above-named Disciplinary Rules for the attorney to remain silent, as to the interrogatory answers, in settlement negotiations. The committee believes that a settlement entered into in reliance on sworn, yet incorrect, answers would be fraudulently induced, whether the attorney verbally reaffirms the incorrect answers or simply remains silent as to their inaccuracy during the negotiations process. See LEOs #1289, 1331, 1429.
Legal Ethics Opinion No. 1451

Confidences and Secrets; Fraud on Tribunal; Knowingly False Statements by Client in Deposition

You have advised that an attorney represents a defendant in a civil matter in which defendant's deposition was taken. Defendant later informs her attorney that she lied about some matters during the deposition. The attorney believes the matters to be irrelevant to the case's merits, but possibly relevant to the defendant's credibility. Defendant's attorney believes the case might settle shortly after the deposition. You indicate further that if the case does not settle, and if the defendant has to testify later, she has indicated she will correct her deposition testimony at that time.

You have asked the committee to opine whether, under the facts of the inquiry, the attorney must, if the defendant is unwilling to do so, disclose the misrepresentation in the deposition testimony.

The appropriate and controlling Disciplinary Rule related to your inquiry is DR 4-101(D)(2) which mandates that a lawyer reveal information which clearly establishes that his client has, in the course of the representation, perpetrated a fraud related to the subject matter of the representation upon a tribunal. Before revealing such information, however, the lawyer shall request that his client advise the tribunal of the fraud. Information is clearly established when the client acknowledges to the attorney that he has perpetrated a fraud upon a tribunal.

The committee has consistently opined that an attorney has a duty to disclose a client's fraud upon a tribunal, if the client refuses to do so. See LEOs #727, #1093, #1140, and #1362.

The committee believes that the answer to your question requires a step-by-step analysis of the impact of DR 4-101(D)(2) on facts you have provided. First, the committee is of the opinion that a knowingly false statement by the client does constitute a "fraud" as articulated in DR 4-101(D)(2). Further, the committee opines that, because the knowingly false statement occurred during the course of pre-trial depositions, the fraud is "related to the subject matter of the representation". The committee is of the view that the disciplinary rule's reference in that regard encompasses a broader interpretation than simply whether or not the fraud impacts upon the merits of the case.

Having concluded thus that the misrepresentation during the deposition does constitute a fraud related to the subject matter of the representation, the committee believes, then, that the answer to your question turns on the final component of DR 4-101(D)(2), i.e., whether the fraud was perpetrated upon a "tribunal". The committee adopts the view of other jurisdictions which have implicitly included depositions within the definition of "tribunal". See, e.g., Committee on Professional Ethics v. Crary, 245 N.W. 2d 298 (Iowa 1979) where a client falsely testified at deposition, the lawyer should have stopped
deposition testimony, remonstrated the client, and revealed the client's perjury to the affected person or court if the client refused to do so). The committee believes the determinative factor to be whether disclosure is necessary to prevent a judgment from being corrupted by the client's unlawful conduct. See ABA Formal Op. 87-353 (1987). The committee believes that it would be unjust to allow the false deposition testimony to stand, regardless of whether the case proceeds to trial.

Thus, in the facts you present, the committee opines that the defendant, in falsely testifying at deposition, perpetrated a fraud related to the subject matter of the representation upon a tribunal. The committee further opines that the defendant's attorney must reveal the client's knowingly false statement (fraud) to the tribunal if the client is unwilling to do so.

Committee Opinion
March 13, 1992
You have presented a hypothetical situation in which a first-year associate at a large law firm was assigned to work on several related anti-trust class action cases approximately three months before leaving the firm to work for a government agency that enforces anti-trust laws. The anti-trust class action cases involve the same or related anti-trust issues, and the associate's firm represents the same single defendant in each case. In all, there are approximately forty defendants, the majority of which had signed a joint defense agreement with the associate's client.

You indicate that the full extent of the associate's involvement in the cases over the three-month period consisted of the following activities:

1. Researched and wrote a draft brief and a memorandum in opposition to class certification in one of the cases. In the course of preparing these procedural documents, the associate had access to its client's files but did not refer to any of those files because the only facts relevant to the brief and memorandum were the plaintiff's allegations, which the associate gleaned from the plaintiff's complaints. The associate also did not have access to any other defendant's files but did receive copies of some privileged joint defense correspondence.

2. Composed a draft answer in one case on behalf of the firm's client only. Reviewed other defendants' draft answers circulated pursuant to a joint defense agreement in the course of selecting language for the draft answer but did not have access to other defendants' files. The associate did not rely upon its client's files in preparing the draft but did have conversations with a more senior associate regarding facts relating to the client. The draft answer was finalized by the more senior associate.

3. Reviewed third-party documents produced to the plaintiffs pursuant to a third-party subpoena; some documents contained information about certain joint defendants.

4. Composed initial draft responses to interrogatories and document requests on behalf of the firm's client. Attended one meeting with the client only (no joint defendants) regarding responses to document requests. A more senior associate performed all the factual investigation for the responses to interrogatories and finalized the draft by filling in the relevant facts. The senior associate also finalized the responses to document requests. Reviewed other defendants' privileged draft objections and responses to interrogatories and document requests in the course of selecting language for the firm's client's draft responses. Did not have access to other defendants' files at any time but did receive and review privileged joint defense correspondence.
discussing joint defense strategy as it affected responding to discovery.

5. Attended one joint defense meeting at which some, but not all, members of the joint defense were represented. The purpose of the meeting was to discuss strategy for responding to interrogatories and document requests. Did not have access to other defendants' files at any time, although some attorneys for other defendants discussed their planned responses to interrogatories and document requests based upon the limited information they had received from their clients up to that date. (The meeting occurred before many attorneys had an opportunity to review their clients' files.)

You further indicate that at no time did the first-year associate have access to any of the other defendants' files, but the associate did receive regularly joint defense correspondence relating to discovery and other aspects of the pending litigation.

Finally, you advise that the associate subsequently began to work for a federal agency that enforces anti-trust laws. You have asked the committee to opine, relative to the facts presented, as to several issues regarding possible conflicts between the associate's present governmental employment and the former clients.

The appropriate and controlling Disciplinary Rules related to your inquiry are DR 4-101 which provides for the preservation of client confidences and secrets; DR 5-105(D) which states that a lawyer who has represented a client in a matter shall not thereafter represent another person in the same or substantially related matter if the interest of that person is adverse in any material respect to the interest of the former client unless the former client consents after disclosure; and DR 5-105(E) which provides that if a lawyer is required to decline employment or to withdraw from employment under DR 5-105, no partner or associate of his or her firm may accept or continue such employment.

The committee opines relative to the facts presented as follows:

1. With regard to whether a lawyer-client relationship exists between the associate and the joint defendants such that DRs 5-105(D) and 4-101 are triggered, the committee is of the opinion that no attorney-client relationship with the co-defendants has been established to which DR 5-105 would be applicable. The committee has previously opined, however, that a potential client's initial consultation with an attorney creates an expectation of confidentiality which must be protected by the attorney, as demanded by DR 4-101, even where no attorney-client relationship arises in other respects. See LEOs #1453, #1546.

In the facts presented, although the associate did not have access to the co-defendants' files, the associate was provided with copies of joint correspondence relating to case facts and strategies. The committee is of the opinion, therefore, that the associate has actually
received confidences and secrets from the co-defendants. Furthermore, the information gained relative to co-defendants is also construed to be protected as a secret of the client/defendant since it was gained in the professional relationship, was apparently intended by the client to remain confidential, and since the interest of the co-defendants is parallel to the interest of the client/defendant. Thus it is the committee's view that although the associate would not necessarily have a conflict related to the joint defendants, it would be incumbent upon the associate to preserve any secrets or confidences received, in accordance with DR 4-101. However, the committee cautions that a determination as to whether any such information was actually received requires an examination of all circumstances by a finder of fact. See, e.g., Duncan v. Merrill Lynch, Pierce, Fenner & Smith, Inc., 646 F.2d 1020, 1027 (5th Cir. 1981).

The committee is of the further opinion that both variations on your inquiry, i.e., (a) whether the co-defendants signed/participated in the joint defense agreement, and (b) whether the co-defendants attended the one joint defense meeting the associate attended, are immaterial to the conclusions reached.

2. Under DR 5­105(D), an attorney shall not represent another person in the same or substantially related matter [emphasis added] if the interest of that person is adverse in any material respect to the interest of the former client unless the former client consents after disclosure.

With regard to the determination of the existence of a "substantial relationship", the committee has not established a precise test for substantial relatedness under DR 5-105(D). The committee, however, has previously declined to find substantial relatedness in instances that did not involve either the same facts (LEO #1473), the same parties (LEOs #1279, #1516), or the same subject matter (LEOs #1391, #1399, #1456).

Under the facts presented, then, the committee would find not substantially related any anti-trust enforcement which did not involve either the same relevant facts necessary to prove a violation, the same parties (the same co-defendants), or the same subject matter (anti-trust). See Tessier v. Plastic Surgery Specialists, Inc., 731 F.Supp. 724, 730-31 (E.D.Va. 1990), and Rogers v. The Pittston Co., 800 F.Supp. 350 (W.D.Va. 1992).

3. With regard to a time limit on any bar against the associate's participation in all kinds of antitrust enforcement, the committee believes that a response to this inquiry has been rendered moot since the committee has opined above that there is no attorney-client relationship between the associate and the co-defendants. However, the committee notes that Disciplinary Rule 5-105(D) does not provide for a time limit on the
prohibition against representing a current client adverse to a former client. The plain language of the Rule provides a total bar to representation, unless consent of the former client, after full disclosure, is received. Furthermore, the committee has previously opined that an attorney's responsibility to preserve a client's secrets or confidences survives the death of the client, thus placing no time limit on such protections. See LEO #1207; see also LEO #1307.

4. As to whether any disqualification that applied to the associate would be imputed to the government agency or the associate's new office, the committee is of the opinion that, since there is no attorney-client relationship between the associate and the co-defendants, the provision of DR 5-105(E) regarding imputed disqualification are inapposite to the facts you present.


Committee Opinion
January 13, 1995
Legal Ethics Opinion 1493

Confidences and Secrets: Confidentiality of Information of Expert Witness Engaged by Attorney's Former Client/Employer

You have presented a hypothetical situation in which Attorney A was previously employed by the Federal Government, during which time, he used B, a contractor, as an expert witness in a case against C. You advise that litigation in the case is ongoing, and the Federal Government continues to use B as an expert witness. Attorney A now works for D. D is being sued by E, a private party, who has called B to testify as an expert.

You indicate that Attorney A has been asked by D whether A can disclose to D information learned by A as to the strengths and weaknesses of B, as well as other aspects of how he works, for use in the litigation involving E.

You have asked the committee to opine whether, under the facts of the inquiry, such disclosure regarding B would violate Attorney A's duty of confidentiality or any other ethical obligations owed to his former employer/client, the Federal Government.

The appropriate and controlling Disciplinary Rule related to your inquiry is DR 4-101, which provides, generally, that an attorney may not reveal or use a confidence or secret of his client, except under certain enumerated circumstances.

The committee is of the opinion that unless A would be revealing confidences or secrets of his former employer/client, the Federal Government, it would not be improper for A to disclose information about the strengths and weaknesses and work habits of his former employer's expert witness. The committee is of the view that the information to be disclosed is not a confidence or secret under the Disciplinary Rule, since it constitutes only a subjective assessment of an expert witness' demeanor and not information gained in the professional relationship. Under the facts you have provided, the present litigation is not related to any past litigation which involved the expert witness' testimony. Thus, the committee finds no ethical duty owed either/client or the expert witness which would inhibit the attorney from conveying his impressions about the expert witness's strengths, weaknesses, or work habits to the new employer who may confront the expert witness as to the current client, E.

Committee Opinion
October 19, 1992
LEO 1299

LEO: Appearance of Impropriety - Former LE Op. 1299

Appearance of Impropriety - Former Government Attorney:
Representation of Client by Former Government Attorney in
Matter in Which He Was Originally Involved While a Public
Employee.

September 13, 1990

The Committee herewith renders its reconsideration of the question as
originally posed, related to prior employment as a government attorney
engaged in rulemaking for the federal government, based upon more recent
and clarified recitation of additional facts, incorporating by reference
the Committee's original opinion rendered on November 16, 1989.

As you recently have stated the facts, an attorney, while a federal civil
service employee, provided legal services and supervised other attorneys
who provided legal services to a federal agency in publishing a proposed
regulation which attempted to define an operative term in a federal
statute, which term was material to the agency's enforcement program as a
result of a consent order negotiated by the attorney in question for the
purpose of resolving litigation between the agency and private parties.
After the agency received public comment in response to the proposed
regulation, the attorney further counseled agency officials concerning (i)
legal issues raised in the public comments and (ii) the effect of the
consent order upon the agency's flexibility in interpreting the statutory
term in question.

You have also indicated that, before the agency took any further action,
the attorney transferred to a position with no responsibility for
providing legal services to the agency concerning the interpretive
regulation. After the attorney transferred, the agency amended the
proposed regulation on two separate occasions, which amended proposals
differed materially from the proposals for which the attorney had had
responsibility. You note that, although the attorney knew of those
developments through informal conversation with other government attorneys
who continued to work on the rulemaking effort, the attorney in question
had no contact with any agency official on the subject.

Further, you inform the Committee that, before the agency adopted its
final rule, the attorney resigned from public employment. More than five
months subsequent to the attorney's resignation, the agency adopted a
final rule substantially in line with the third of its proposals rather
than with the first of its proposals for which the attorney in question
had substantial responsibility.

Finally, you indicate that, prior to accepting employment offered by a
private party in litigation challenging the substance of the agency's
adoption of the final rule as arbitrary, capricious, or inconsistent with
law, the attorney requested an opinion from the agency's ethics official.
The official rendered an opinion indicating that such employment would not
violate federal statutory or regulatory restrictions on post-employment
conduct by former federal employees, but indicating also that the
determination by the official did not address the requirements of legal canons of ethics which might be of concern in the attorney's situation.

You have requested that the Committee opine as to the propriety of the attorney's accepting employment by a private party who challenges the substance of the agency's adoption of the final version of the rule which you indicate differed materially from the initial proposed rule for which the attorney had substantial responsibility. You have specifically indicated that no challenge was being posed as to the procedure by which the agency adopted the rule.

The Committee reiterates its reference to DR:9-101(B) and Ethical Consideration 9-3 which provide that, in order to avoid even the appearance of impropriety, a lawyer shall not accept private employment in a matter in which he had substantial responsibility while he was a public employee. Furthermore, the Committee reiterates its opinion that the permissive nature of the United States Code's post-employment provisions does not vitiate the provisions of Virginia's Code of Professional Responsibility as embodied in DR:9-101(B). Finally, the Committee also reiterates its opinion which construes the term "matter" as broad enough to encompass rulemaking.

Under the specific additional and clarified facts of your inquiry, however, the Committee is of the opinion that the attorney's substantial responsibility in the matter of the proposed regulation ended when the new rule was ultimately promulgated utilizing a third draft for which the attorney had had no substantial responsibility and which differed substantially from the original [first] draft for which the attorney had had substantial responsibility. Thus, under the facts you have now stated, it is the opinion of the Committee that it would not be improper for the attorney to accept employment by private parties challenging the substance of the rule as arbitrary, capricious or inconsistent with the law, provided that the language of that rule was proposed and adopted subsequent to any proposal on which the attorney had worked and for which he had had substantial responsibility.

However, the Committee cautions the attorney that the Code of Professional Responsibility's mandate, exhorting the lawyer to preserve a client's secrets and confidences is not diminished by the passage of time. (See DR:4-101; LE Op. 1207, LE Op. 672) In addition, the Committee cautions that a balance must be struck between the mandates of DR:7-101, directing the attorney to zealously represent the client, and the requirements of DR:4-101. Thus, if the preservation of the former client's secrets and confidences negatively impacts upon the zealous representation of the new [private] client challenging the rule, the attorney's less-than-zealous representation would be improper.

Rule 1.6: Confidentiality of Information

Client-Lawyer Relationship
Rule 1.6 Confidentiality Of Information

(a) A lawyer shall not reveal information relating to the representation of a client unless the client gives informed consent, the disclosure is impliedly authorized in order to carry out the representation or the disclosure is permitted by paragraph (b).

(b) A lawyer may reveal information relating to the representation of a client to the extent the lawyer reasonably believes necessary:

(1) to prevent reasonably certain death or substantial bodily harm;

(2) to prevent the client from committing a crime or fraud that is reasonably certain to result in substantial injury to the financial interests or property of another and in furtherance of which the client has used or is using the lawyer's services;

(3) to prevent, mitigate or rectify substantial injury to the financial interests or property of another that is reasonably certain to result or has resulted from the client's commission of a crime or fraud in furtherance of which the client has used the lawyer's services;

(4) to secure legal advice about the lawyer's compliance with these Rules;

(5) to establish a claim or defense on behalf of the lawyer in a controversy between the lawyer and the client, to establish a defense to a criminal charge or civil claim against the lawyer based upon conduct in which the client was involved, or to respond to allegations in any proceeding concerning the lawyer's representation of the client; or

(6) to comply with other law or a court order.
Rule 1.7 Conflict of Interest: Current Clients

Client-Lawyer Relationship

Rule 1.7 Conflict Of Interest: Current Clients

(a) Except as provided in paragraph (b), a lawyer shall not represent a client if the representation involves a concurrent conflict of interest. A concurrent conflict of interest exists if:

(1) the representation of one client will be directly adverse to another client; or

(2) there is a significant risk that the representation of one or more clients will be materially limited by the lawyer's responsibilities to another client, a former client or a third person or by a personal interest of the lawyer.

(b) Notwithstanding the existence of a concurrent conflict of interest under paragraph (a), a lawyer may represent a client if:

(1) the lawyer reasonably believes that the lawyer will be able to provide competent and diligent representation to each affected client;

(2) the representation is not prohibited by law;

(3) the representation does not involve the assertion of a claim by one client against another client represented by the lawyer in the same litigation or other proceeding before a tribunal; and

(4) each affected client gives informed consent, confirmed in writing.

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Rule 1.9: Duties of Former Clients

Client-Lawyer Relationship
Rule 1.9 Duties To Former Clients

(a) A lawyer who has formerly represented a client in a matter shall not thereafter represent another person in the same or a substantially related matter in which that person's interests are materially adverse to the interests of the former client unless the former client gives informed consent, confirmed in writing.

(b) A lawyer shall not knowingly represent a person in the same or a substantially related matter in which a firm with which the lawyer formerly was associated had previously represented a client

(1) whose interests are materially adverse to that person; and

(2) about whom the lawyer had acquired information protected by Rules 1.6 and 1.9(c) that is material to the matter;

unless the former client gives informed consent, confirmed in writing.

(c) A lawyer who has formerly represented a client in a matter or whose present or former firm has formerly represented a client in a matter shall not thereafter:

(1) use information relating to the representation to the disadvantage of the former client except as these Rules would permit or require with respect to a client, or when the information has become generally known; or

(2) reveal information relating to the representation except as these Rules would permit or require with respect to a client.
NOTES
The Nuclear Industry in a Post-Fukushima World
U. S. Nuclear Generating Fleet

Strengthening Safety Post Fukushima

Presented By Jim Scarola
2011- External Events

- March 11\textsuperscript{th} - Fukushima Daiichi Overcome by Tsunami
- April 28\textsuperscript{th} --Browns Ferry Hit by Tornados
- June 26\textsuperscript{th} – Ft. Calhoun Impacted by Missouri River Flood
- August 23\textsuperscript{rd} – North Anna Impacted by Northeast Earthquake
Fukushima Impact

Design
- External Events (Seismic, Flooding, Wind) Basis Validation
- Loss of all AC power (Blackout) and Loss of Heat Sink
- Venting of Containments
- Spent Fuel Pool Instrumentation

Programs
- Periodic inspection and maintenance of passive design requirements for External Events
- Periodic testing of beyond design basis equipment
- Adding Diverse Equipment for multiple beyond Design Basis events

Response
- Upgrading the Procedures, Training, Periodic Drills for Emergencies, Severe Accidents, and Extensive Damage Mitigation Guidelines
- Upgrade capabilities and organizational capacity to address prolonged multiple simultaneous events
- Industry coordinated response capability
Industry Response Coordination

The Way Forward

Fukushima Response Steering Committee

Nuclear Supplier Owner’s Groups
- Strategies for EOP, SAMG, EDMG

EPRI
- Technology use and advancement
- External event assessment

INPO
- Event analysis and lesson learned
- Immediate Actions for US Industry

NEI
- Industry Coordinated response
- Regulatory Interface
- Stakeholder Communications

Continued Support of TEPCO, WANO, IAEA in Stabilization and Clean-up
## INPO Event Report 11-1

### Severe Event Mitigation

<table>
<thead>
<tr>
<th>Recommendation 1</th>
<th>Beyond Design Basis Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Beyond Design Basis B.5.b Equipment walked down, inspected, and tested</td>
<td></td>
</tr>
<tr>
<td>• Procedures validated through demonstration</td>
<td></td>
</tr>
<tr>
<td>• Training and qualifications verified</td>
<td></td>
</tr>
<tr>
<td>• Support contracts as required to respond are current and in place.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Recommendation 2</th>
<th>Station Blackout</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Verify all material needed to execute Station Blackout Procedures is adequate and staged</td>
<td></td>
</tr>
<tr>
<td>• Validate through walkdowns that procedures for Station Blackout are executable</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Recommendation 3</th>
<th>Internal / External Flooding</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Verify through walkdowns and inspections that all equipment and materials required to mitigate flooding are adequate and properly staged. Include door, barrier, and penetration seals.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Recommendation 4</th>
<th>Fire / Flood Mitigating Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Walkdown and identify equipment needed to mitigate a fire or flood that could be lost during a seismic event. (Include water tanks, intake structures) Develop mitigating Strategies for vulnerabilities</td>
<td></td>
</tr>
</tbody>
</table>
**INPO Event Report 11-1, Supplement 1**

**Severe Event Mitigation Program Controls**

**Recommendation 1**
Change Management

- Program controls, ownership, and oversight to ensure that station commitments from B.5.b and severe accident management guidelines are not impacted by modifications, procedure and training program changes.

**Recommendation 2**
Equipment and Passive Design Maintenance

- Verify passive and active equipment utilized for B.5.b and SAMG are maintained through preventive maintenance strategies.

**Recommendation 3**
Training and Qualification

- Verify training and qualifications for execution of B.5.b and SAMG are commensurate with the complexity and time critical nature of the actions. Include in training program descriptions.

**Recommendation 4**
Drills

- Perform periodic drills on a period not to exceed eight years of time critical actions for B.5.b, SAMG, flooding, and station blackout.
- Every three years verify applicable contracts and agreements are in place with local, state, and federal organizations and suppliers.
<table>
<thead>
<tr>
<th>Recommendation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>SOER 09-1 Recommendations 1-4 and 6-12 should be implemented as they relate to the Fuel pools</td>
</tr>
<tr>
<td>2</td>
<td>Protect equipment and functions required for Fuel Pool Cooling when Time to boil is less than 72 hours</td>
</tr>
<tr>
<td>3</td>
<td>Calculate Time to boil for all plant conditions of the Spent Fuel Pool and make it readily available in the Control Room and Emergency Response Facilities</td>
</tr>
<tr>
<td>4</td>
<td>Establish Abnormal Operating Procedures for loss of Spent Fuel Pool cooling and ensure guidance can be executed during seismic, flooding, severe weather, and loss of control room. Ensure Temperature and level monitoring</td>
</tr>
<tr>
<td>5</td>
<td>Revise Emergency Operating Procedures to ensure Spent Fuel Temperature and Level are monitored</td>
</tr>
</tbody>
</table>
# INPO Event Report 11-3

**Operator Fundamentals**

<table>
<thead>
<tr>
<th>Recommendation 1</th>
<th>Training Effectiveness</th>
</tr>
</thead>
<tbody>
<tr>
<td>Evaluate the effectiveness of the training program in the area of operator fundamentals</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Recommendation 2</th>
<th>Operator Fundamentals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assess operator fundamentals and identify gaps that exist that could cause events or reduce crew effectiveness in responding to transients</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Recommendation 3</th>
<th>Leader Behaviors and Practices</th>
</tr>
</thead>
<tbody>
<tr>
<td>Communication of expectations in regard to fundamentals</td>
<td></td>
</tr>
<tr>
<td>Role in ensuring quality training on fundamentals</td>
<td></td>
</tr>
<tr>
<td>Role in monitoring and engaging operators in fundamentals</td>
<td></td>
</tr>
<tr>
<td>Review of significant transient response to validate fundamental performance</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Recommendation 4</th>
<th>Crew Team Dynamics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crew composition is adjusted to optimize experience, backgrounds, and personalities</td>
<td></td>
</tr>
<tr>
<td>Ensure newly constituted crews train together</td>
<td></td>
</tr>
<tr>
<td>Ensure shift manager lead critiques of crew performance and have timely continuous improvements</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Recommendation 5</th>
<th>Sustainability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Use corrective action program, performance indicators, and self assessments to identify, track, and trend the application of fundamentals</td>
<td></td>
</tr>
</tbody>
</table>
# INPO Event Report 11-4

**Loss of All AC Power Concurrent for Multi-Unit**

<table>
<thead>
<tr>
<th>Recommendation</th>
<th>Description</th>
</tr>
</thead>
</table>
| **Recommendation 1**  
24 Hour Coping Time | • Develop methods to maintain or restore core cooling, containment integrity, and fuel pool inventory using installed and portable equipment with extended loss of AC for 24 hours  
• Define proposed upgrades needed to meet 24 hours |
| **Recommendation 2**  
Monitoring | • Identify essential instruments needed to monitor core, containment, and spent fuel safety.  
• Develop methods to ensure availability of these instruments during an extended loss of AC event, include equipment and materials needed once batteries are depleted |
| **Recommendation 3**  
Fuel for Emergency Equipment | • Develop strategies for obtaining fuel to keep Emergency equipment operational in the extended loss of AC power. On-site reserves can be utilized if protected from seismic and flood. |
| **Recommendation 4**  
Communications | • Provide communications equipment needed for on-site and off-site personnel that will function with an extended loss of all AC to supporting infrastructure within 25 miles of the site. |
INPO 11-005 November 2011

Special Report on the Nuclear Accident at the Fukushima Daiichi Nuclear Power Station

Revision 0
Safety Assurance for Unpredicted Events

Initiating Events

I. Design Basis
   (Redundancy & Qualification)
   - Cooling / Make-up Water
   - Power

II. Beyond Design Basis
    (Diversity & Quantity)
    - B.5.b Pumps
    - Deep Well Pumps
    - Portable Generators
    - Battery Packs
    - Compressors / Gas Bottles

III. Fuel Damage Impact Management
     (Coordination, Command & Control)
     - Venting and Release Path Filtration
     - Evacuation / Shelter
     - Potassium Iodine Usage
     - Industry Response

IV. Recovery After Stabilization
    (Coordination, Command & Control)
    - Quick Hits
    - Apparent Root Cause
    - Lessons Learned
    - Industry Support

OP / AOP / EOP / SAMG / EDMG

Public and Environmental Protection

Seismic Flood Unknown
Presentation to the
Energy Bar Association

December 1, 2011

William D. Magwood, IV
Commissioner
The Energy Reorganization Act of 1974 divided the Atomic Energy Commission into a “promotional” technology development agency – the Department of Energy – and a regulatory agency – the NRC.

NRC is 4000 people dedicated to assuring the safe and secure use of nuclear materials in the United States in order to protect and safety of the American people.
**What We Regulate**

- **Nuclear Reactors** - commercial power reactors, research and test reactors, new reactor designs.
- **Nuclear Materials** - nuclear reactor fuel, radioactive materials for medical, industrial, and academic use.
- **Nuclear Waste** - transportation, storage and disposal of nuclear material and waste, decommissioning of nuclear facilities.
Fukushima Daiichi
Changing the Shape of the Future
Fukushima Daiichi
Before the Tsunami

• 4696 MWe Nuclear Power Plant operated by Tokyo Electric Power Company

• Six Boiling Water Reactors (BWRs) based on US designs—brought on-line between 1971 and 1979

• Most of the plant’s output was used to provide electricity to Tokyo

• TEPCO had planned to construct two advanced BWRs at the site beginning in 2012
Fukushima Daiichi on March 11
A Bad Day At the Plant

- Magnitude 9.0 earthquake followed by 15 meter tsunami at the plant
- Extended Station Blackout
- Batteries depleted and subsequent loss of all reactor cooling
- Core damage in units 1, 2, and 3
- Hydrogen explosions in reactor buildings housing units 1, 3, and 4
Fukushima Daiichi

After the Tsunami
U.S. Government Response
Multi-Agency Assistance

**NRC**
- Provided modeling and analytical support to U.S. and Japanese organizations.
- Deployed expert team to Japan with experience including:
  - BWR reactor safety systems
  - Dose assessment
  - Protective measures

**DoD**
- Provided $88.6 million in humanitarian assistance
- Conducted USAR operations and transport of USAR cargo
- Deployed search and rescue teams to Japan to conduct missions utilizing canines and listening devices

**FEMA**
- Deployed search and rescue teams to Japan to conduct missions utilizing canines and listening devices

**HHS**
- Provided expert advice regarding the use of potassium iodide or the need to switch to bottled water for Americans in Japan

**DOE /NNSA**
- Provided specialized robotic equipment to Japan
- Conducted various nuclear analyses
- Provided aerial measurement systems
- Conducted thousands of air and field samples in Japan
- Analyzed samples at U.S. national labs

**AID**
- Coordinated overall USG relief efforts.
- Deployed a Disaster Assistance Response Team to support emergency response.
- Provided $6.3 million in humanitarian assistance, including urban search and rescue (USAR) activities.

**U.S. Embassy Japan**
- Focal point for relief efforts and information point for American citizens in Japan
NRC Near-Term Task Force
U.S. Plants Are Safe

TASK FORCE CONCLUSIONS

• No imminent risk from continued operation and continued licensing activities
• Similar events in the U.S. very unlikely.
• Mitigation measures already in place could reduce the likelihood of core damage and radiological releases.

KEY RECOMMENDATIONS

• Reevaluate design-basis seismic and flooding protection.
• Strengthen station blackout mitigation capability.
• Require reliable hardened vents in boiling water reactors.
• Enhance spent fuel pool makeup capability and instrumentation.
• Strengthen and integrate onsite emergency procedures.
• Require emergency plans to address prolonged station blackout and multiunit events.
**After Fukushima**

**Learn the Big Lessons**

- Understand the Risks Facing Each Plant
- We Can’t Predict Every Event
- Recovering from Disaster is At Least as Important as Preparing for Disaster
- Potential for Common Cause Failure of On-Site and Off-Site AC Power
The NRC continues to review five technologies and 12 license applications to build new Generation III+ power plants in the U.S.
Nuclear Industry in a Post-Fukushima World:
Economic Risk and Capital Adequacy

Stephen Maloney
December 1, 2011

Participants at the Energy Bar Association's meeting of December 1, 2011 are authorized to make copies for their own personal use. No representation is made that any information contained herein is fit for any purpose.
Systemic Risk In Today’s Markets

Systemic risk is the highly correlated response to common events

- The currency wars among increasingly insolvent governments (and their entitlement and pension programs) have fueled the carry trade, increasing correlations across asset classes.
- As a consequence, the banking sector has been in steady decline for more than a decade, despite ZIRP and multiple rounds of QE. EU banks are down 31% this year alone; US banks 22%.
- Enterprises protect themselves against systemic risk by shoring up their capital base and maximizing liquidity.
- With insolvent governments issuing ever more debt, systemic risk is rising.

Figure 16—Implied probability of systemic stress episode

SPDR Select Sector Fund - Financials

[Graph showing financial data over time]
Take-Aways

- Risk management is a formal governance framework, independent of the business unit, that prices financial exposure to an enterprise, and manages risk capital's alignment either by (1) raising equity and contingent capital or (2) shedding risk.

- Compliance with NRC public health and safety standards is not risk management. Nor are probabilistic risk assessments and the “risk-informed” modifications.

- Fukushima revised upward long-standing estimates of economic exposures from accidents at power reactors.

- Capital markets now recognize nuclear generating companies as an asset class with characteristics very similar to a population of under-capitalized primary dealers and over-leveraged banks – susceptible to losses from a significant event.

- In the post-Fukushima era, generating companies can expect market pressures to (1) improve the balance between risk and capital or (2) seek even more backing from increasingly insolvent governments and those who actually pay taxes.
The Station Blackout Rulemaking

A short version of a much longer story

- An “unresolved safety issue” (USI) identified in the Reactor Safety Study of early-1970s identifying gaps in the General Design Criteria (GDC) used to license power reactors.

- In the mid-1980s, NRC proposed 10 CFR 50.63 which assumed GDC compliance and protection against external hazards (systemic risk from earthquake, fire, and tsunami) except where defects were known (e.g., SEP plants) or new information becomes available (e.g., revised seismic standards).

- Station blackout rule focused on a subset of events associated with extended loss of AC power to core cooling systems, related to coincidental occurrence of random, independent (“stochastic”) events.

- Where plants faced unacceptable systemic risk, remedies would be provided by orders, or timely implementation of enhancements under the subsequent rulemakings for A-45 (Decay Heat Removal) or A-46 (Seismic) expected in the late 80s-early 90s.

- NRC’s Fukushima Task Force revisits A-45 and A-46 some 20 years later – and over 35 years after Browns Ferry.
In March, 2011, the $37 billion Tokyo Electric Power Company (TEPCO) exceeded the market cap all US nuclear operators.

![Market Capitalization Diagram]

- Pinnacle West
- SCANA Corp.
- NRG Energy Inc.
- Ameren
- Constellation Energy Group
- DTE Energy
- Entergy Corporation
- Edison International
- PPL Corporation
- Progress Energy, Inc.
- Public Service Enterprise Group
- PG&E Corp.
- FirstEnergy Corp.
- American Electric Power
- NextEra Energy
- Duke Energy Corporation
- Dominion Resource
- Exelon Corp.
- Southern Company
## Fukushima Dai-ichi

<table>
<thead>
<tr>
<th>Reactor</th>
<th>Gross Capacity</th>
<th>Design</th>
<th>Commercial</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit 1</td>
<td>460 MWe</td>
<td>BWR-3/Mark I</td>
<td>March 26, 1971</td>
</tr>
<tr>
<td>Unit 2</td>
<td>784 MWe</td>
<td>BWR-4/Mark I</td>
<td>July 18, 1974</td>
</tr>
<tr>
<td>Unit 3</td>
<td>784 MWe</td>
<td>BWR-4/Mark I</td>
<td>March 27, 1976</td>
</tr>
<tr>
<td>Unit 4</td>
<td>784 MWe</td>
<td>BWR-4/Mark I</td>
<td>October 12, 1978</td>
</tr>
</tbody>
</table>
US BWRs

• **Nine Mile Point Unit 1**
  - Scriba, NY (6 miles northeast of Oswego)
  - Operating License Originally Issued December 26, 1974
  - GE BWR 2, Mark I containment
  - Electrical Output 621 MWe

• **Pilgrim Nuclear Power Station**
  - Plymouth, MA (38 miles southeast of Boston)
  - Operating License Originally Issued June 8, 1972
  - GE BWR 3, Mark I containment
  - Electrical Output 683 MWe

• **Peach Bottom Units 2 and 3**
  - Delta, PA (17.9 miles south of Lancaster, PA)
  - Operating Licenses Originally Issued October 25, 1973 and July 2, 1974
  - GE BWR 4, Mark I containment
  - Electrical Output 1112 MWe, each

Source: US Nuclear Regulatory Commission
Fukushima (on March 14, 2011)

Source: DigitalGlobe
Fukushima Units 3 (right) and 4 (left): March 20, 2011

Source: Air Photo Service Co Ltd., Japan
Contamination

Source: Asahi Shimbun
Tokyo Electric Power Company – Too Big to Fail

- Socializing (some of) the risk with a government bailout
  - Jun 11: Downgraded to junk status
  - Aug 11: $1.2 trillion loss reported (~30 times its pre-accident market cap)
  - Oct 11: Latest damage estimate of 1 trillion yen. TEPCO and the Nuclear Damage Liability Facilitation Fund, a government-backed entity, jointly submitted a business plan to the Economy, Trade and Industry Ministry calling for costs of up to 2.5 trillion yen over 10 years.

![TEPCo Adjusted Closing Prices](chart.png)
Re-evaluating Creditworthiness for Global Nuclear Generators (April 7, 2011):

“What is changing is our view of the sheer magnitude of liability associated with an event risk occurrence. For companies with nuclear activities, Fukushima highlights two important fundamental assumptions incorporated into our credit analysis: an assumption that a population is willing to accept the costs of radiation and that its government will stand behind long-term liabilities. These assumptions are expected to be tested over the next 12 to 18 months” [emphasis added]

“The resolution regarding Japan’s government support for liabilities can have contagion effects on other jurisdictions. For example, in the United States, the Price Anderson Act limits liability to nuclear operators at only $12.5 billion, a figure which now appears relatively low. Any liabilities above that level are expected to be absorbed by both state and federal governments, a concept that could create a political backlash for the sector due to the weak economic recovery and deteriorating state of government finances. At this time, we would not rule out the potential for significant changes to the US nuclear sector’s liability insurance framework.” [emphasis added]

“Issuers that own nuclear generating assets within the unregulated power market frameworks are more exposed than issuers operating within a traditionally regulated market framework. Recovery of increased costs associated with political intervention and heightened regulatory scrutiny are more assured in a regulated framework. Similarly, the US municipal electric utility and G&T cooperative issuers, virtually all of whom have full rate setting autonomy, can recover increased costs provided they fully exercise that autonomy even in the face of a potential consumer backlash.” [emphasis added]
Correcting Station Blackout Risk Estimates

Standard PRA estimates do not properly treat bias

PRA is subject to convexity bias:
(1) significant range of exposures
(2) adjusting for convexity bias increases median expected CDF by factors of 2-10

Further bias in treatment of dependent failure/systemic risk:
(1) seismic hazard, system independence, and pipe fragility
(2) multi-unit effects
(3) risk fragility of certain containments

Plant-Specific SBO CDF

<table>
<thead>
<tr>
<th>Reactor Count</th>
<th>CDF (RY-1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>5.0E-05</td>
</tr>
<tr>
<td>20</td>
<td>4.5E-05</td>
</tr>
<tr>
<td>40</td>
<td>4.0E-05</td>
</tr>
<tr>
<td>60</td>
<td>3.5E-05</td>
</tr>
<tr>
<td>80</td>
<td>3.0E-05</td>
</tr>
<tr>
<td>100</td>
<td>2.5E-05</td>
</tr>
</tbody>
</table>

95% Frequency
- Median Frequency (Convexity Bias Arithmetically Corrected)
- Median Frequency (Convexity Bias Geometrically Corrected)
- Median Plant-Specific CDF
- 5% Frequency
Rising Exposures

Nuclear risk tends to rise over time due to:

- Population growth over plant life
- Urbanization increases real estate value and economic census
- GDP deflator effects

Population Density (per sq-mile)

Fukushima Prefecture

<table>
<thead>
<tr>
<th>Year</th>
<th>Barnstable County</th>
<th>Plymouth County</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>500</td>
<td>700</td>
</tr>
<tr>
<td>2000</td>
<td>550</td>
<td>750</td>
</tr>
<tr>
<td>1990</td>
<td>400</td>
<td>600</td>
</tr>
<tr>
<td>1980</td>
<td>350</td>
<td>500</td>
</tr>
<tr>
<td>1970</td>
<td>300</td>
<td>450</td>
</tr>
<tr>
<td>1960</td>
<td>250</td>
<td>400</td>
</tr>
</tbody>
</table>
Capital Adequacy of US Nuclear Gencos

- **Exposure:** $125-$150 billion
  - BAML and TEPCo business plan estimates comprising third party damages, replacement power (mostly LNG) and site remediation

- **Capital:** ~$26 billion
  - Market Cap: ~$15 billion
  - Trust: ~$1 billion
  - Contingent capital: ~$10 billion
  - Implicit put option to the Federal Government
US Natural Gas Supply

Shale gas supply continues to grow - reducing US demand for LNG and other fuels

- Northeast US: explosive supply growth, especially in Pennsylvania
- US Dry Shale Gas: Increased in 2010 from 1.0 trillion cubic feet in 2006 to 4.8 trillion cubic feet, 23% of total U.S. dry natural gas production
- US Wet Shale Gas Reserves: increased to about 60.64 trillion cubic feet by year-end 2009, 21% of overall U.S. natural gas reserves
Spent Fuel—No Good News

Mary Anne Sullivan
maryanne.sullivan@hoganlovells.com
December 1, 2011

Washington, DC
To get you in the mood . . .

• The Fukushima tsunami and meltdown
• The Eurozone crisis
• The federal deficit
• The stock market 5-year performance
• The unemployment rate
• The foreclosure rates in Nevada, Florida, California, Arizona, Michigan

Now we are ready to talk about spent nuclear fuel
Word association: Spent fuel policy means . . .

- Blue Ribbon Commissions: many
- National Academy studies: too many to count
- Expensive
- Futile exercise
- Black hole
- Political football
- Litigators’ paradise
- At-reactor storage
A very brief history

- 1940’s: First large volumes of high level waste
- 1956: First NAS study on spent fuel
- 1957: First commercial spent fuel
- 1982: Congress: study diverse sites
- 1987: Congress: study only Yucca Mountain
- 1998: Yucca does not open: lawsuits filed
- 2002: Yucca found suitable for repository
- 2008: DOE files NRC licensing application
- 2008: Candidate Obama: Yucca is out
History continued

• 2010: ASLB denies DOE motion to withdraw Yucca application.
• 2011: D.C. Circuit: challenge to withdrawal not ripe
• 2011: Equally divided Commission affirms ASLB, but closes down licensing: no budget
• 2012: Blue Ribbon Commission final report
• 2012: D.C. Circuit to rule on DOE Yucca license application withdrawal
• 2040: A repository ? ? ? ? (if Yucca not revived)
(Latest) Blue Ribbon Commission (draft)

• Failure to build consensus was fatal flaw in spent fuel policy—need consent-based approach
• Pursue interim storage—preferably regional
• Pursue one or more geologic disposal sites in parallel
• Coordinate with corridor states
• Reprocessing not the answer
• NAS should study deep borehole disposal—again
• Move the function out of DOE (away from politics)
Spent Fuel Costs

• $15 billion spent on Yucca characterization and licensing efforts
• $16.2 billion in utility lawsuit judgments by 2020
• $500 million/year in judgments post-2020
• Utility fees for spent fuel $750 million/year

More than 60 “Solyndras” and counting . . .
Spent Fuel Realities

- 1987 NWPA approach a bad idea
- No perfect solution
  - Concept of “consent-based” siting has failed repeatedly
  - BRC idealizes 25-year WIPP approval process
- No quick solution
  - Challenge to pursue both interim storage and disposal
  - Transportation plan alone could take a decade
- Policy paralysis is fodder for nuclear opponents
- Cost a serious policy driver
The view going forward

• New legislation required unless Yucca revived—and maybe even if it is

• Industry support needs to be steadfast, realistic
  – Industry needs to take the long view—don’t assert every claim, fight every fight

• Siting success will take money and more

• The Standard Contract will be revised
  – Spent fuel will almost certainly be the problem of new reactor owners, not the government’s, until there is a clear solution
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*Associated offices
BIOGRAPHIES
Darren Bush is a Professor of law at the University of Houston Law Center. Professor Bush received his Ph.D. in economics from the University of Utah, where he focused primarily on competition policy as applied to regulated industries.

Professor Bush served as an Attorney General's Honor Program Trial Attorney at the Antitrust Division's Transportation, Energy, & Agriculture Section. Since returning to academia in 2001, he has written and consulted on numerous issues concerning the intersection of antitrust and regulated industries. He has testified before the U.S. House and U.S. Senate Judiciary Antitrust Subcommittees, the Federal Energy Regulatory Commission and the U.S. Antitrust Modernization Commission, the latter with which Professor Bush consulted.

His primary research interests are in antitrust and deregulated industries (and the intersection of the two, including airlines, telecommunications, electricity, and surface transportation), intellectual property, and law & economics.
John M. Eber, Managing Director, Energy Investments
JPMorgan Capital Corporation

John Eber manages the firm’s activities for tax motivated equity investments in energy assets. He directs a team of twenty professionals who originate, structure and execute investments and advise other equity co-investors. Additionally, he oversees Energy Investments’ product development activities, management of its investment portfolio and is a member of its Investment Committee.

Since 2003 John has been responsible for approximately $7.1 billion of renewable energy tax equity including financings for approximately 7,300 MWs of wind power in 75 wind farms, 73 MW of solar power in 13 projects, including the largest CSP solar transaction in the U.S. in 15 years and four geothermal projects totaling 53 MW. Over the past 18 years he has been responsible for approximately $8.3 billion worth of tax equity energy investments for J.P. Morgan and its predecessor companies. He has been with J.P. Morgan and its predecessor companies Bank One and First Chicago since 1988.

John has been a member of the Board of Directors of the American Wind Energy Association (AWEA) since 2007 and is a frequent panelist and speaker for a variety of organizations including AWEA, the Solar Energy Industries Association (SEIA) and the American Council on Renewable Energy (ACORE).

John received a B.S. degree in economics from Bradley University, Peoria, Illinois and a MBA with a specialization in finance from DePaul University, Chicago, Illinois.
BIOGRAPHY

Ms. Edwards has been practicing administrative and regulatory energy law before the FERC for over thirty years, specializing in natural gas regulation. She is the owner of Edwards & Associates, a boutique law firm that has been in existence for nine years. Edwards & Associates represents major and independent producers, marketers, and shippers on natural gas and oil pipelines before the FERC and federal appellate courts.

Ms. Edwards received a BA degree with honors in mathematics and philosophy from Randolph-Macon Woman’s College, an MA degree with highest honors in philosophy from Memphis State University, and a JD degree from the University of Texas in Austin, where she was a member of the Texas Law Review.

She has published numerous articles in energy trade publications, and has been active in the Energy Bar Association and the American Bar Association. She was Chair of the Section of Public Utility, Communication and Transportation Law, of the American Bar Association, from 1999-2000. She is a member of the District of Columbia Bar and the Virginia State Bar, and her law firm is located in Alexandria, Virginia. Contact information is below.

Katherine B. Edwards
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1517 King Street
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Mason Emnett, Associate Director

Mason Emnett is Associate Director of the Office of Energy Policy and Innovation at the Federal Energy Regulatory Commission. The Office provides leadership in the development and formulation of policies and regulations to address emerging issues affecting wholesale and interstate energy markets.

Mr. Emnett joined the Commission in 2006, serving as Senior Legal Advisor in the Commission's Office of General Counsel. There he advised the Commission on legal and policy matters related to electric transmission service, wholesale power sales, electric system reliability, corporate regulation of public utilities, and enforcement proceedings. Prior to joining the Commission, Mr. Emnett was in private practice with the law firm of Skadden, Arps, Slate, Meagher and Flom LLP in Washington, D.C, where he represented public utilities appearing before the Commission on matters related to market design, wholesale rates, mergers and acquisitions, and regulatory compliance.

Mr. Emnett is a graduate of the Georgetown University Law Center and of the University of Texas at Arlington.

Updated: June 28, 2010
H. Russell Frisby, Jr.

Russell is a partner in the Washington, D.C. office of Stinson Morrison Hecker LLP. His practice focuses on regulatory and corporate matters affecting entities in the communications, energy and technology areas. For more than 20 years, he has represented clients in a wide variety of proceedings, including litigation matters, before the Federal Communications Commission (FCC), state utility commissions and federal courts. Russell’s professional experience includes serving as CEO and acting chief legal officer of the Competitive Telecommunications Association, which is the largest association representing competitive facilities-based carriers, providers using unbundled network elements, global integrated communications companies, and their supplier partners.

Previously, Russell served as chairman of the Maryland Public Service Commission. During his tenure, the commission was renowned for its pro-competitive policies in telecommunications, gas and electricity matters. Russell participated in a number of key decisions, including the Telecommunications Act arbitration proceedings, various rate cases and the electric industry restructuring.
Rob Gramlich is Senior Vice President of Public Policy for the American Wind Energy Association, the national trade association of approximately 2500 entities involved in all aspects of wind energy production, based in Washington DC. Rob joined AWEA in 2005 and now leads the association's strategic initiatives related to federal and state legislation, industry information and analysis, and regulatory policy. He has published articles on wind integration, carbon taxes, market power regulation, and electricity capacity markets. He has testified before the Federal Energy Regulatory Commission (FERC) and state commissions. He serves on the U.S. Department of Energy's Electricity Advisory Committee.

Rob served as Economic Advisor to FERC Chairman Pat Wood III, and has worked for PJM Interconnection, PG&E National Energy Group, World Resources Institute, and the Lawrence Berkeley National Laboratory.

Rob has a Masters degree in Public Policy from UC Berkeley and a B.A. in economics from Colby College.
W. Colin Harper  
Senior Vice President – Corporate Development

Colin Harper is Senior Vice President of Corporate Development for NiSource Gas Transmission & Storage (NGT&S). Harper is responsible for the development of new growth opportunities outside of NGT&S’ existing asset profile. Prior to assuming this position, Harper was responsible for all commercial activities including marketing and supply origination, system optimization & logistics, gas control, fuel strategies, measurement and customer services for the regulated pipeline and storage unit. Harper had previously joined NGT&S as Senior Vice President of Business Development.

Harper has been involved in marketing, operations, project development and fuel management in the gas and electric industries for 30 years. Prior to joining NGT&S in 2008, he served in various leadership roles with Transco Energy Company, Cogen Technologies (The McNair Group) and Gdf-SUEZ (formerly Tractebel Energy).

Harper has served as an At-Large Board Member of the Natural Gas Supply Association and is a member of the Southern Gas Association and the National Energy Supply Association.

Harper earned a Bachelor of Science degree from the University of Southwestern Louisiana.
Mr. Hepper received a Bachelor of Science degree in 1976 from Lehigh University, summa cum laude, and a Juris Doctorate from the University of Pennsylvania Law School in 1979. He is admitted to practice law in New Jersey, Pennsylvania, Maine and Massachusetts.

Mr. Hepper joined ISO New England in June of 2004. As Vice President, General Counsel and Corporate Secretary, he is the principal legal advisor for ISO New England, and is responsible for coordinating all legal and regulatory activities. ISO New England is the independent system operator for New England. In addition to operating the bulk electricity system for the region, ISO New England administers the wholesale electricity marketplace, as well as the Open Access Transmission Tariff on behalf of the New England Power Pool. ISO New England is based in Holyoke, Massachusetts.

Mr. Hepper began his legal career as an Appellate and Review Attorney at the U.S. Department of Justice. In 1989 he joined Central Maine Power Company in Augusta, Maine as a tax attorney, and after four years he made the transition to regulatory law as Assistant General Counsel, where he was responsible for all proceedings before the Maine Public Utilities Commission and the Federal Energy Regulatory Commission. In 1994, he became General Counsel at CMP. When he departed in 2000, he was managing the Legal, Rates, Environment, and Regulatory departments. Immediately before joining ISO New England, Mr. Hepper was a partner at Pierce Atwood in Portland, Maine, where he specialized in Energy & Utility Regulation, representing clients in a variety of matters related to power transmission, complex regulatory proceedings, transactions and contract negotiations.
The Honorable William D. Magwood, IV was sworn in as a Commissioner of the U.S. Nuclear Regulatory Commission (NRC) on April 1, 2010, to an initial term ending on June 30, 2010, and a reappointment term ending June 30, 2015.

Mr. Magwood has a distinguished career in the nuclear field and in public service. He was the longest-serving head of the United States' civilian nuclear technology program, serving two Presidents and five Secretaries of Energy from 1998 until 2005.

Mr. Magwood served seven years as the Director of Nuclear Energy with the U.S. Department of Energy (DOE), where he was the senior nuclear technology official in the United States Government and the senior nuclear technology policy advisor to the Secretary of Energy. He oversaw the restoration of the Federal nuclear technology program and led the creation of "Nuclear Power 2010," "Generation IV," and other innovative initiatives—including efforts that helped reverse the decline in American nuclear technology education. Before his appointment to lead the Office of Nuclear Energy, he served four years as its Associate Director for Technology and Program Planning.

During his tenure at DOE, Mr. Magwood was recognized as a strong advocate of international technology cooperation and served as Chairman of both the Generation IV International Forum and the Organization for Economic Co-operation and Development (OECD) Steering Committee on Nuclear Energy. After his DOE service, Mr. Magwood founded and headed Advanced Energy Strategies, a company that provided strategic advice to domestic and international organizations.

Prior to his appointments at DOE, Mr. Magwood managed electric utility research and nuclear policy programs at the Edison Electric Institute in Washington, D.C. Before that, he was a scientist at Westinghouse Electric Corporation in Pittsburgh, Pennsylvania.

Mr. Magwood holds a B.S. degree in physics and a B.A. degree in English from Carnegie-Mellon University. He also holds an M.F.A. degree from the University of Pittsburgh.
Stephen Maloney brings over 30 years asset valuation and risk management experience in energy, commodities, FX, alternative investments, and fixed income. Stephen’s clients include Tier 1 banks, hedge funds, asset managers and international energy firms in North America, Europe, Russia, the Middle East, and the Pacific Rim in oil, natural gas, LNG, wind energy, hydro, and transmission. His nuclear experience began as a commissioned officer in the US Navy’s nuclear propulsion program where he first qualified as an engineering watch officer and later as chief engineer. Stephen’s commercial nuclear experience encompasses ATWS, TMI Action Plan, Appendix R, equipment qualification, and station blackout. Stephen was licensed as a professional engineer, and has degrees in physics, mathematics, and operations research. He is a member of the Global Association of Risk Professionals, the Professional Risk Management International Association, the Institute for Operations Research and the Management Sciences, and the American Mathematical Society.
Mark J. Niefer is an attorney at the Antitrust Division of the U.S. Department of Justice. Since joining the Division, he has worked on matters involving a variety of industries, including airlines, agriculture, and electricity. His work on electricity has included co-authoring regulatory filings at the Federal Energy Regulatory Commission; testifying before FERC on merger analysis; and leading several non-merger and merger investigations, including Division’s investigation of the Exelon-PSEG merger, which ended with the filing of a consent decree requiring divestiture of several generating plants. Prior to joining the Antitrust Division, Mark was an economist at Pacific Northwest National Laboratory, where he conducted research related to the effect of new technology on productivity and energy consumption. He holds a J.D. and a Ph.D. in economics.
DAVID K. OWENS

David K. Owens is Executive Vice President of Business Operations at the Edison Electric Institute. Mr. Owens has responsibility over the strategic areas of energy supply and the environment, energy delivery, energy services, and international affairs. The group focuses on a broad range of issues that affect the future structure of the industry and new rules in evolving competitive markets.

Previously, Mr. Owens served as EEI's Senior Vice President of Finance, Regulation, and Power Supply Policy, focusing on enhancement of industry representation on such issues as the Public Utility Regulatory Policies Act (PURPA), the Public Utility Holding Company Act (PUHCA), the Federal Power Act, cogeneration and independent power production, transmission access, and bulk power and transmission pricing, which affect the national interest. He also represented the industry in the areas of finance, ratemaking, regulation, accounting, and taxes.

Mr. Owens also served as Vice President, Power Supply Policy, overseeing a broad range of issues related to power supply policy and the regulatory structure of the electric utility industry. He joined EEI in 1980 as Director of Rates and Regulation. His responsibilities included coordinating industry positions on rate-related matters before Federal, Executive and Congressional committees.

Prior to EEI, Mr. Owens served as Chief Engineer of the Division of Corporate Regulation of the Securities and Exchange Commission. This division is responsible for regulating public utility holding companies. Mr. Owens also was an engineer in the Division of Rates and Corporate Regulation at the former Federal Power Commission and worked as a design and test engineer for General Electric and Philadelphia Electric Companies, respectively.

Mr. Owens holds a BS and Masters Degree from Howard University and a Masters in Engineering Administration from George Washington University.
Biography

Executive Director of the Steyer-Taylor Center for Energy Policy and Finance

Dan Reicher '83 has more than 25 years of experience in energy and environmental technology, policy, finance and law, including serving in the Clinton administration at the Department of Energy (DOE) as assistant secretary for energy efficiency and renewable energy. He recently was a member of President Obama’s transition team, where he focused on the energy portions of the stimulus package and was an adviser to the Obama campaign on energy and climate issues. Reicher comes to Stanford University from Google Inc., where he served since 2007 as director of climate change and energy initiatives.

Reicher is also a member of the National Academy of Sciences Board on Energy and Environmental Systems, co-chairman of the board of the American Council on Renewable Energy, and a member of the boards of the American Council for an Energy Efficient Economy, the Apollo Alliance, and the University of California-Davis Energy Efficiency Center.

Before his position at Google, Reicher served as president and co-founder of New Energy Capital Corp., a private equity firm funded by the California State Teachers Retirement System and Vantage Point Venture Partners to invest in clean energy projects. He also served as executive vice president of Northern Power Systems, one of the nation’s oldest renewable energy companies. Reicher was also an adjunct professor at the Yale University School of Forestry and Environmental Studies and Vermont Law School.

Reicher has also held several positions with the DOE, the Senate Environment and Public Works Committee, the World Resources Institute and the Natural Resources Defense Council. He also worked for the Massachusetts Attorney General, served as a law clerk to a federal district court judge in Boston and as a legal assistant in the Hazardous Waste Section of the U.S. Department of Justice, and was on the staff of President Carter's Commission on the Accident at Three Mile Island. Reicher holds a BA in biology from Dartmouth College and a JD from Stanford Law School. He also studied at Harvard's Kennedy School of Government and MIT.

In the News

- Subsidy Nation: Can U.S. Firms Compete Against China?
  The Wall Street Journal, October 21, 2011

- How Bright Is Solar Power's Future In A Post-Solyndra America?
  PBS Newshour, October 18, 2011

- Analysis: Solyndra Casts Shadow On U.S. Energy Loan Aid
  Reuters, October 06, 2011
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**Education**

• BA, Dartmouth, 1978
• JD, Stanford Law School, 1983
Sidney Rocke, J.D. is the Deputy Associate General Counsel for General Law at the Federal Energy Regulatory Commission. He is also the Commission’s Alternate Designated Agency Ethics Official and is actively involved in the Commission’s ethics advisory and training functions. Mr. Rocke is a former federal prosecutor and Maryland Assistant Attorney General. He has handled numerous trials and court appearances nationwide, and regularly testified before Congress and state legislatures. Mr. Rocke has also taught in a variety of settings, including the FBI Academy and Georgetown University and has written for a number of publications, including the Washington Post, Baltimore Sun, and Legal Times of Washington. He received his law degree from George Washington University, and a B.A. in Communication Studies from the University of Massachusetts.
RICK SMEAD is a director for Navigant Consulting, Inc. (Navigant). In this position, he is responsible for managing Navigant’s consulting business in the midstream natural gas industry, concentrating on regulatory and commercial issues in the interstate gas pipeline market. He has been responsible for multiple engagements involving potential acquisitions, policy analysis, litigation support, and strategic advice with respect to gas pipelines, potential supplies, and market initiatives. The highest profile of his recent engagements was the management and preparation of the North American Natural Gas Supply Assessment for the American Clean Skies Foundation, a ground-breaking 2008 analysis of the health and potential of the U.S. natural gas industry. Otherwise, a significant concentration of his practice has involved the downstream market and infrastructure issues affecting liquefied natural gas (LNG) projects. His clients have included interstate gas pipeline companies, midstream natural gas companies, major producing companies, gas distribution companies, industry trade associations and foundations, national oil companies, and U.S. government agencies. He has been active on the subject of allowed rates of return, authoring a widely publicized white paper on the subject in 2006 for the Interstate Natural Gas Association of America (INGAA) which led in part to changes in the Federal regulatory policy regarding pipeline rates of return. A similar effort was completed in 2008 for the American Gas Foundation.

Until joining Navigant in 2004, Mr. Smead held various senior management positions in the interstate natural gas pipeline industry, including Vice President, Regulatory Policy for the El Paso Pipeline Group, Senior Vice President, Regulatory Affairs and Tax for Colorado Interstate Gas Company, and Senior Vice President Regulatory Affairs for ANR Pipeline Company. Until 1988, he was Director of Rates for the Tenneco Gas Group. Overall, his management responsibilities included over a dozen major natural gas pipeline companies owned by these entities, spanning the United States. He was active and instrumental in the overall industry restructuring under Order No. 636, filed and resolved 27 major pipeline rate cases, and led multiple industry policy initiatives. Prior to joining Tenneco in 1980, Mr. Smead held various positions with Washington Gas Light Company, a large urban local distribution company in Washington, D.C.

Mr. Smead holds a Bachelor of Science degree in mechanical engineering from the University of Maryland and a Juris Doctor degree from George Washington University. He is a member of the District of Columbia Bar and the Energy Bar Association (EBA), where he served as Chairman of the Natural Gas Regulation Committee from 2006 to 2008 and as a co-chair of the Program and Meetings Committee in 2008-09. He presently serves as Treasurer and a member of the board of directors of the Foundation of the Energy Law Journal, and as a member of the board of directors of the Houston Chapter of EBA.

Mr. Smead has testified over twenty-five times before the Federal Energy Regulatory Commission, other regulatory and taxing agencies, and various civil courts. He has been active in the international arena, advising various entities in Australia and other countries as to the design of a privately owned pipeline industry. More recently, he has advised national oil companies and non-U.S. corporations regarding the U.S. pipeline infrastructure and market dynamics relevant to LNG projects.

During his tenure in the pipeline industry, Mr. Smead served as chairman of the INGAA Rate Committee and of various ad hoc task groups focused on specific issues. He served as chairman of the American Gas Association (AGA) Rate Committee from 1988 to 1991 and earlier as chairman of the joint AGA/Edison Electric Institute Depreciation Committee. He is a past member of the Board of Directors of the North American Energy Standards Board, where he served as vice chair of the gas-electric interaction task force. He is a frequent speaker and author on gas industry matters.
Regina Y. Speed-Bost is a Partner at Schiff Hardin LLP. She graduated from Georgetown University Law Center in 1990 and was admitted to the District of Columbia Bar in 1990. Ms. Speed-Bost concentrates her practice in energy administrative and regulatory law matters. She advises natural gas companies, local distribution companies, energy marketers and electric utilities on matters related to: compliance with FERC rules, regulations and governing statutes, NERC rules and Standards, FERC standards of conduct compliance, the interpretation of FERC’s Enforcement Authority, negotiations and investigations pursuant to FERC’s Enforcement Authority, the operation of regional transmission organizations, open Access Transmission Tariff (OATT) operations, and the interplay of federal wholesale regulation and state and local retail regulations. Ms. Speed-Bost is a regular speaker at numerous seminars and conferences. She was recently named one of the Diversity Journal’s 2012 Women Worth Watching.
Mary Anne Sullivan

Mary Anne Sullivan is a partner in the Energy Group at Hogan Lovells US LLP in Washington, DC, where she has a broad-based energy practice covering nuclear, climate change, electricity, advanced energy technology and related matters.

Mary Anne served as general counsel of the U.S. Department of Energy (DOE) from 1998 to 2001 and as Deputy General Counsel For Environment and Nuclear Programs from 1994 to 1998.

Of particular relevance to her presentation today, as General Counsel and Deputy General Counsel of DOE, Mary Anne provided legal support for the opening of the Waste Isolation Pilot Plant (WIPP), the world’s first (and highly successful) deep geologic repository for radioactive waste, and for the now-cancelled Yucca Mountain spent fuel repository. She defended against many legal challenges to both. She now represents both utility and non-utility members of the nuclear industry.
Michael J. Thompson
Shareholder

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Michael Thompson has 30 years of experience representing natural gas and electric clients before the Federal Energy Regulatory Commission (FERC), state regulatory agencies, state public utility commissions, and appellate courts. Mr. Thompson counsels clients on a wide variety of regulatory and commercial matters.

His work includes managing, litigating, and negotiating settlements in rate, rulemaking, and complaint proceedings; negotiating agreements for the development or transfer of energy infrastructure assets; litigating market power and other competition-related issues in a variety of regulatory settings; and assisting with management of pre-construction environmental review and permitting for gas and oil pipeline projects.

Mr. Thompson has extensive experience advising regional transmission organizations (RTOs) and independent systems operators (ISOs) on matters including developing tariffs, regional transmission planning and market rules, developing and obtaining regulatory approval of contracts for the interconnection of generation and merchant transmission facilities.

Representative Experience

Representing Kern River Gas Transmission Company in litigating a multi-party, ongoing FERC rate proceeding; assisted in driving FERC to adopt new policy employing publicly traded master limited partnerships in establishment of pipelines’ rates of return on equity. Won FERC approval to establish new rates based on 100% equity capital structure to be effective after expiration of firm shippers’ current service agreements.

Practice Areas
Electric Energy Regulation
Natural Gas & Oil
Transmission & Distribution

Education
B.S., cum laude, The Ohio State University, 1977

Honors/Distinctions
Chambers USA, Energy: Oil & Gas, 2004-2011
The Best Lawyers in America, Energy Law, 2006 - 2011

Bar/Court Admissions
District of Columbia
Virginia
U.S. Court of Appeals, District of Columbia Circuit
U.S. Court of Appeals, Federal Circuit
U.S. Court of Appeals, Fourth Circuit
U.S. Court of Appeals, Fifth Circuit
U.S. Court of Appeals, Tenth Circuit
U.S. Court of Appeals, Eleventh Circuit
U.S. District Court, District of Columbia
U.S. District Court, Eastern District of Virginia
U.S. Supreme Court

Professional Affiliations
Energy Bar Association
Foundation of the Energy Law Journal, Board of Directors, 2005-2010
Natural Gas Roundtable
U.S. Association for Energy
Represented a natural gas pipeline client in compliance audits and advised on potential enforcement issues.

Represented Transcontinental Gas Pipe Line Corporation in multi-party rate litigation before FERC, resulting in settlements of many issues, litigated resolutions of remaining issues.

Represented a RTO in obtaining FERC approval of various revisions of market rules and tariffs, including provisions governing performance of demand response resources; pricing of cross-border energy transactions; and terms and conditions for interconnection of new generation and merchant transmission facilities, among others.

Represented a landowner in negotiating and documenting long-term lease for construction of merchant, natural gas-fired generating plant.

Economics
American Bar Association, Section on Energy, Environment, & Resources; Public Utility, Communications, and Transportation Law
Andy Tunnell is a Partner with Balch & Bingham LLP. His practice principally involves the representation of the transmission function of large electric utilities before federal and state agencies and appellate courts. His specific areas of practice include:

- Proceedings and rulemakings before the Federal Energy Regulatory Commission involving the regulation of electric transmission.
- Proceedings before the Alabama Public Service Commission and the Florida Public Service Commission involving electricity regulation.
- Appellate litigation involving issues pertaining to energy companies.

Specifically with regard to FERC Order No. 1000, Andy worked on the request for rehearing filed by the Ad Hoc Coalition of Southeastern Utilities, a filing that was sponsored by eleven electric utilities in the Southeast, including both FERC-regulated and non-jurisdictional utilities.