U.S. Department of Energy
Washington, DC 20585

Date: October 6, 2014

To: Members of the Public

From: Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff, United States Department of Energy

Re: QER Public Stakeholder Meeting: Financing Energy Infrastructure (Transmission, Storage, and Distribution)

1) Introduction

On January 9, 2014, President Obama issued a Presidential Memorandum establishing a Quadrennial Energy Review (QER). The Secretary of Energy provides support to the QER Task Force, including coordination of activities related to the preparation of the QER report, policy analysis and modeling, and stakeholder engagement.

On Monday, October 6, 2014, at 9:30 AM EST at New York University Kimmel Center for University Life, Room 914, 60 Washington Square South, New York, New York, 10010, the U.S. Department of Energy (DOE) will hold a public meeting to discuss and receive comments on issues surrounding the financing of energy transmission, storage, and distribution infrastructures (TS&D) that link energy supplies to intermediate and end users.

This meeting is the 13th in a series of QER stakeholder meetings, which have been held throughout the country, focusing on opportunities and challenges surrounding energy TS&D infrastructure. Prior meetings have focused on infrastructure resiliency, electricity TS&D challenges, natural gas and liquid fuel transmission opportunities and constraints, sectoral interdependencies, and other issues.[1] This meeting will focus broadly on the financing of energy TS&D infrastructure, and seeks to incorporate input from the investor, industry, and other stakeholder communities. Assets including pipeline systems, power transmission lines, local distribution networks, storage facilities, liquid fuel refineries, gas processing facilities, railroads, roads, barges, and import and export terminals will be considered.

There will be an opportunity for public comment via an open microphone session following panel discussions. Written comments can be submitted to QERcomments@hq.doe.gov. The session will also be webcast at www.energy.gov/live.

2) Background

Over the past decade, the United States has seen a dramatic transformation across virtually every aspect of its energy portfolio. From feedstock to feeders, new capabilities and challenges have tunneled through the status quo of nearly every sector. For example, the country has experienced a dramatic increase in the domestic production of natural gas and liquid fuels through hydraulic fracturing, horizontal drilling, and other technologies, along with challenges in the transport of these fuels. For power or electricity, blossoming new generation sources and technologies, such as natural gas, renewables, and storage, have

[1] For a full list of previous QER meetings, visit www.energy.gov/qer

stretched operators into a more nimble posture. In pipelines and distribution circuits alike, new resources are reversing the direction of molecules and electrons, upending a century of historical flows. These physical network changes have reverberated onto energy company balance sheets and business models, often composed on assumptions of supply scarcity or demand growth.

Against this crescendo of rapid change stands the nation's energy security, environmental and economic competitiveness goals. Central to enabling these goals is the modernization of the nation's transmission, storage, and distribution infrastructures, which sustains the physical-economic dance of energy supply and demand. Modernization efforts include asset replacement, connecting new sources to demand, upgrading for resilience and efficiency, and reducing environmental footprint. Due to the large capital costs, long life-times, and largely private-ownership of these assets, barriers to the financing of current and future energy infrastructure is a critical issue that will be included in the QER.

The investment profiles for energy infrastructure occupy a continuum from low risk and return to high risk and return projects. This variation depends on the degree of market regulation, industry trends, technology maturity, and regional differences. At the stable end of the risk and return spectrum, electric and gas utilities that provide distribution services to consumers use well established infrastructure financing structures and benefit from the steady tempo of regulatory oversight. For most utilities, local, state, and federal regulations require reliable service at a just and reasonable price; this relative stability both lowers the financial risk associated with their projects and limits the overall return. At the volatile end of spectrum, merchant projects without a guaranteed customer base are free to seek market-based prices. Although riskier, these projects can offer a higher return.

Ultimately, capital will flow to US energy TS&D infrastructure only if the risk and return profile of energy TS&D projects are more attractive than alternative investment options. For example, while institutional investors (e.g., pension, insurance, and mutual funds) may hold trillions of dollars of financial assets, only a fraction of TS&D projects may resonate with the a portfolio's desired risk and return profile. More broadly, this attractiveness depends on industry, market, regulatory, and policy conditions and outlook, in addition to financing structures and project specifics.

Investment in TS&D infrastructure can face many policy frameworks and categories which may act as incentives or barriers; those listed below are not intended to be mutually exclusive or rigidly defined:

- Large **policy** uncertainties can lead to significant market uncertainty, and consequently, aversion to large capital investments in infrastructure that may be potentially stranded.
- Lack of **markets** or effective **market incentives**, especially those associated with externalities or desired capabilities, can lead to underinvestment in useful assets.
- **Regulatory processes** can include regulations that increase the transaction cost (e.g. time) of developing new and desirable projects; conversely, lack of certain regulations may not incentivize desired infrastructure or services.
- **Informational** barriers can preclude clear cost-benefit analyses, and reduce dissemination of best practices and market transparency.
- New **technologies** may face barriers from unproven commercial performance or operations, leading to potential risk; they also enable goals and objectives in ways unanticipated by markets
- **Financial** factors include costs of capital or availability of capital

Infrastructure investments must generate a positive financial return in order to attract investors. Policy and market structures establish the potential revenues that would form a positive business case. Even with a positive business case, regulatory processes may delay progress, and informational barriers may prevent approval by the relevant decision makers. Even after the need for a project has been ascertained, the choice of technology may introduce risk or cost that adds complexity to project completion. Finally, the availability and cost of capital are issues common across all potential investments.

The following sections explore major trends in the electricity, natural gas, and liquid fuels TS&D sectors, and then consider barriers that could affect the financing of new or modernized TS&D infrastructure.

3) Electricity Transmission, Storage, and Distribution

The U.S. transmission and distribution system delivers approximately 4,000 TWh[2] annually from electric power generators through an asset base of nearly 283,000 miles of high voltage transmission wires, 70,000 substations, and 2.2 million miles of local distribution circuits.[3] The U.S. grid also contains 24.6 GW of electricity storage, of which 1.2 GW is comprised of non-hydro technologies such as thermal, compressed air, batteries, and flywheels.[4] Entities that ultimately serve end users include investor-owned utilities, municipally-owned utilities, cooperatives, and federal power agencies (Figure 1). Many electricity distribution companies also own natural gas distribution networks. Other ownership structures exist for transmission, distribution and energy storage assets. This section will provide an overview of trends common across the electricity sector, and examine considerations for selected sub-sectors.

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[2] Energy Information Administration, Annual Energy Outlook 2014, May 7, 2014
[3] Harris Williams & Co., “Transmission & Distribution Infrastructure” 2010
[4] U.S. DOE, “Grid Energy Storage,” December 2013

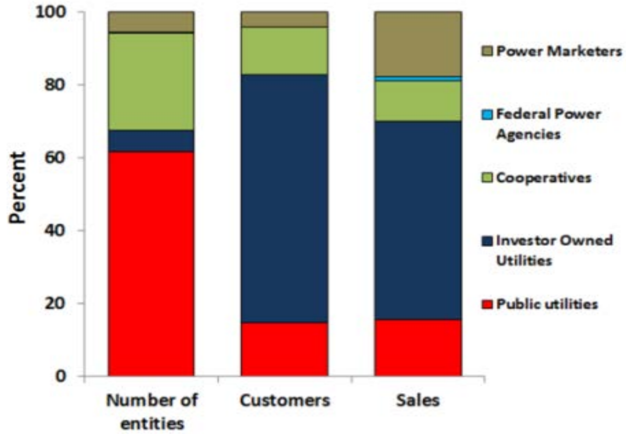

Figure 1: Quantification of utility types, number of customers, and sales, for companies that deliver electricity to end users.[5]

3.1) *Emerging Trends Shaping Infrastructure Finance and Investment*

Since the days of Insull and the Edison franchises, investors have provided the capital to build electricity infrastructure.[6] Recent growth in transmission investment (Figure 2) has been driven by load growth (albeit non-uniform), maintaining reliability, and changes in generation, both to connect renewable generation and to respond to thermal plant retirements.[7]

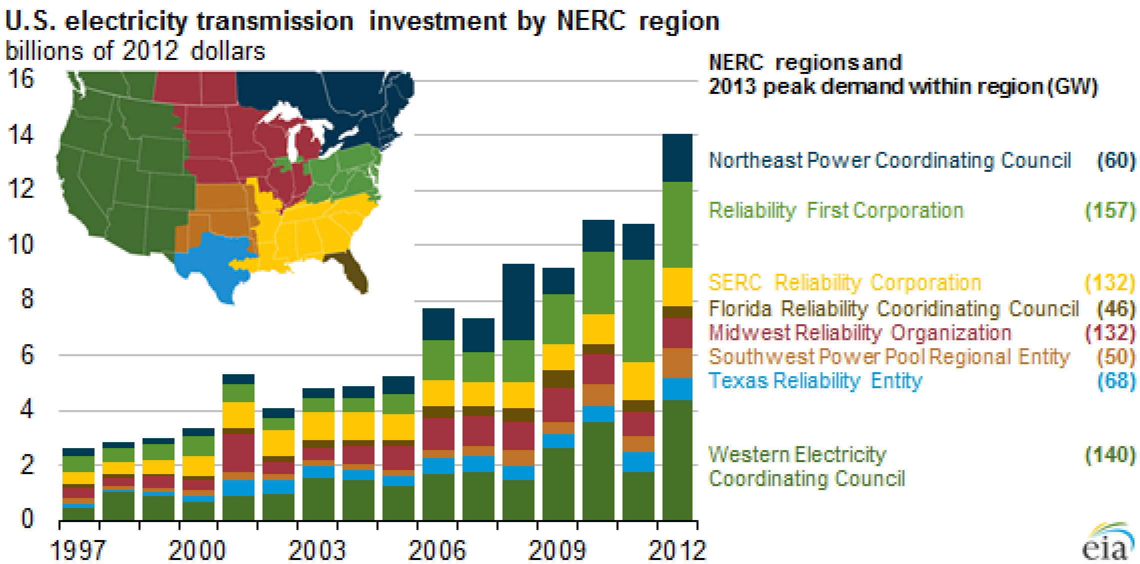

Figure 2: Rate of investments in electricity transmission from 1997 to 2010[8]

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[5] EPSA Analysis, based on EIA data
[6] Insull, Samuel, "Central Station Electric Service," 1917
[7] DOE QER Task Force Secretariat, "Stakeholder Meeting on Electricity," September 8, 2014
[8] Energy Information Administration (EIA), "Electricity transmission investments vary by region," *Today In Energy*, September 3, 2014

Distribution upgrade drivers include weather resiliency and replacement of equipment past service life. Investment needs for electric infrastructure have been estimated to be as high as $2 trillion between 2008 and 2030, with $298 billion directed toward transmission and $582 billion toward distribution systems.[9] While compound annual growth rates (CAGR) for transmission investment grew to 14.1% in 2012 for transmission, growth in distribution investment has increased at a slower pace, to 5.2% in the same year.[10]

Multiple factors will shape future investment in transmission and distribution. These include uncertain costs, slower demand growth largely due to efficiency measures, changes in the generation fuel mix, small but growing increase in distributed generation, and new demands for reliability and security, which are also contributing to higher costs of capital. Finally, low cost and abundant natural gas resources, increasing use of renewable resources, and increase end-use efficiency are changing long term planning and investment profiles.

In addition, utilities face a range of uncertainties that will likely contribute to rising costs. Contributors to increased transmission costs may include support of legacy infrastructure; environmental regulations; state renewable portfolio standards (RPS); nuclear plant safety mandates; and changes in the cost of capital.[11] Similarly, distribution costs may increase due to increased deployment of rooftop solar, increased demand for reliable service, and the potential for new demand (such as from electric vehicles). Across transmission and distribution, adequate access to debt capital markets is essential for meeting and funding these complex requirements. Utilities are currently benefiting from consistently low cost debt but cannot expect it to persist indefinitely. Future interest rate increases would be accompanied by higher utility capital costs, which will ultimately be passed on to the consumer in the form of higher prices.

Electricity load growth has decreased dramatically since the 1950's (Figure 3)[12], due to factors such as changing weather patterns, technological efficiency, behavioral changes, and economic changes. Low growth stresses the regulated utility business model (historically built on increased demand) when profitability is linked to selling more electricity. Despite flat to low growth, utilities must still make new investments for reasons outlined above.

[9] Brattle Group, Chupka, M.W., "Transforming America's Power Industry: The Investment Challenge 2010-2030," November 2008

[10] Black and Veatch, "Building a T&D Investment Program to Satisfy Utility Customers, Regulators & Shareholders," March 27, 2014

[11] Deloitte. The math does not lie. Factoring the future of the U.S. electric power industry. 2012

[12] EIA, Annual Energy Outlook 2014, May 7, 2014

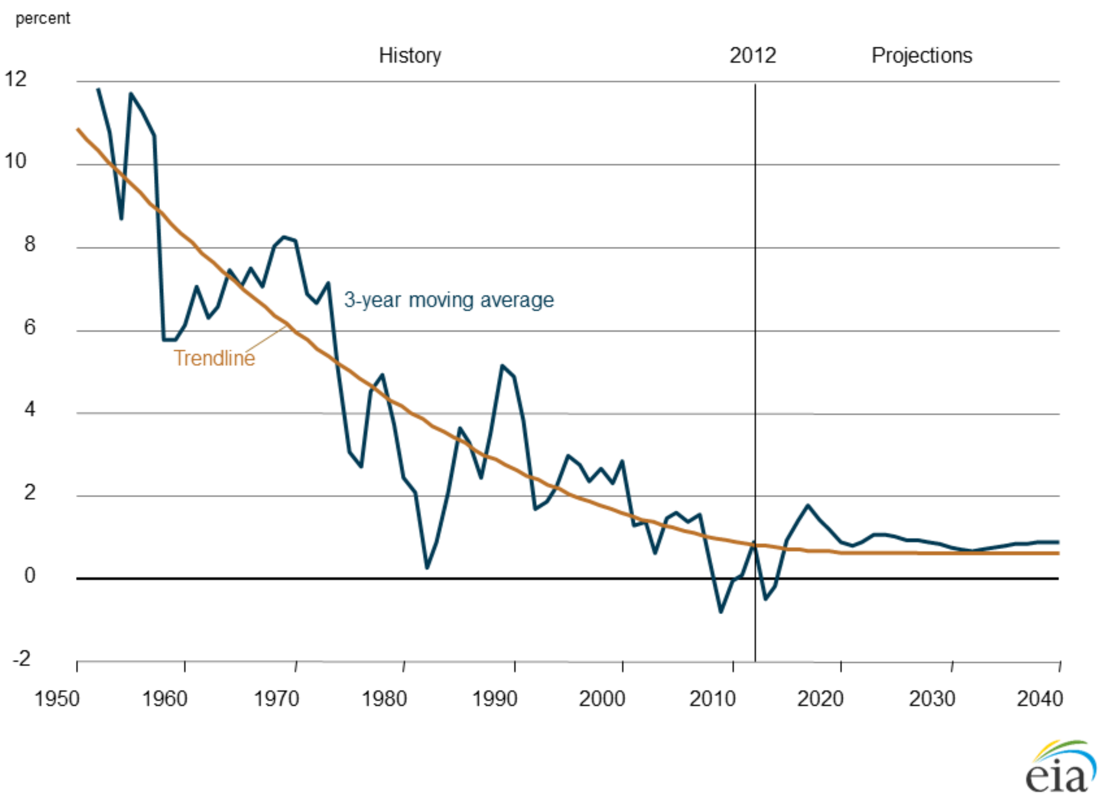

Figure 3: Declining load growth over time[13]

3.2) *Private Sector Infrastructure Financing*

The majority of electric infrastructure financing occurs through the private sector. A relatively small number of private entities (47 parent companies controlling 240 subsidiaries[14]) is responsible for ~55% of electricity sales[15] and finances the largest fraction of electric infrastructure at over $92 billion dollars in 2013 alone (Figure 1). [16] Of all the capital expenditures for IOUs, electricity transmission and distribution infrastructure accounts for almost half of annual investments (Figure 4).

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[13] EIA, Annual Energy Outlook 2014, May 7, 2014
[14] Edison Electric Institute, "U.S. Member Company Service Territories," updated August 2014
[15] Energy Information Administration, Sales (consumption), revenue, prices & customers, March 2014
[16] SNL, "Capital Expenditure Update: November 2013," November 8, 2013

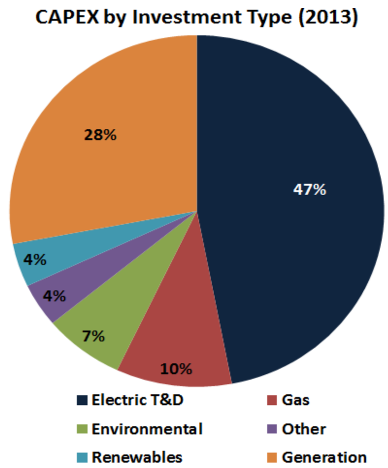

Figure 4: Investor owned utility expenditures by area[17]

In addition to IOU investment, new entities are entering the market to build transmission assets. These entities include transmission-only developers, independent transmission companies (often spun out of formerly vertically integrated utilities), non-core energy companies, and generation-focused independent power producers. According to a 2011 survey, 30% of future high voltage (greater than 345 kV) transmission investments have been proposed by non-incumbent transmission entities.[18]

Regulatory Constraints on Private Sector Finance

Regulated asset owners recover their capital and operations/maintenance costs plus a margin as measured by the Return on Equity (ROE). The ROE is set in a general rate case hearing, where a public utility commission balances the need for new spending against the public objective to minimize rates.

There has been a slow but steady decrease in the average authorized ROE from approximately 13 percent in 1990 to today's value of approximately 10 percent,[19] which reflects the underlying drop in treasury rates. Current low interest rates have reduced infrastructure financing costs to a level that is lower today than at any other time in recent history. While low costs have been argued as a reason to aggressively build out new infrastructure,[20] overly ambitious efforts could result in stranded assets if long-lived equipment is not used.[21]

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[17] Ibid.
[18] IHS, "U.S. Transmission Markets and Strategies: 2011-2020," November 2011
[19] Stephen G. Hill, "What is ROE and Why Does it Matter," 2013
[20] Lawrence H. Summers, "Idle workers + Low interest rates = Time to rebuild infrastructure," Boston Globe, April 11, 2014
[21] A. S. Cook and R. L. Coxe, "A Review of the Financial Risk Profile of Transmission and Distribution Companies in Australia," November 2001

Steady, Long-Term Declines in Investor Owned Utility Credit Ratings

IOU credit ratings have steadily declined over the past 30 years, as shown in Figure 5. In 1970, about 60% of electric utilities were rated AA- or higher. Today, less than 5% of the industry is rated AA- or higher. [22] Although most utilities still maintain investment grade status (BBB and above) there are currently utilities with 'junk' ratings (BB and below), few utilities rated AA, and no AAA rated utilities.

Power supply-side cost pressures, declining economic and customer growth rates, and an evolving industry and regulatory model have resulted in steady erosion in credit quality over each of the last five decades.[23] New competitive forces such as rooftop solar may lead to further credit erosion.[24] Non-investment grade ratings may lead to rerating of capital costs, reduced credit availability, and a change in investor receptivity to the sector. Investors in higher risk debt must be compensated with higher interest returns, which lead to higher capital costs. Therefore, a ratings decline could translate to increases in customer rates.

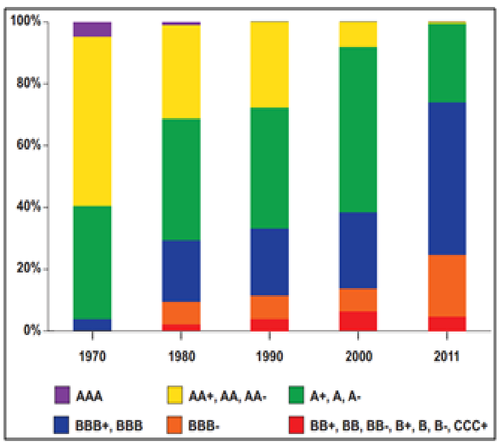

Figure 5: The proportion of electric IOUs with investment grades (AAA, AA, A, BBB) credit ratings has declined over time.[25]

3.3) Public Sector Infrastructure Financing

There are over 828 municipal electric utilities and 20 state utilities that constitute the public electric utility sector.[26] Municipal and state utilities have two primary means of financing energy infrastructure assets: general obligation bonds and revenue bonds. A general obligation bond is a common type of municipal bond that is secured by a state or local government's pledge to use legally available resources, including

[22] Edison Electric Institute. Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business. 2013. www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf.
[23] Atamturk and Zafar, "Trends in Utility Infrastructure Financing," CPUC, August 2012
[24] Barclays Credit Research, "U.S. High Grade Electric - Downgrading to Underweight" May 20, 2014
[25] Edison Electric Institute. Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business. 2013
[26] EIA, "Electric power sales, revenue, and energy efficiency Form EIA-861," May 20, 2014, http://www.eia.gov/electricity/data/eia861

tax revenues, to repay bond holders. Since tax revenues can be increased to cover general obligation bond debt, it is considered the lowest risk bond type and benefits from correspondingly low borrowing costs.

The second major bond type is the revenue bond, which is the predominant financing vehicle for publicly-owned electric and gas utilities. Revenue bonds guarantee bond repayment through the revenue generated by a specific project such as a water treatment plant or electrical utility. Due to the inelastic demand for the services from these assets, as well as the lack of a competitive market, revenue bonds used to finance essential infrastructure have lower borrowing costs than non-essential projects that have competition (i.e. hospitals, and toll roads). Although revenue bonds for essential infrastructure exhibit a lower cost than other projects, revenue bonds are generally associated with higher costs than general obligation bonds.

The cost of capital will vary according to the credit rating of the issuing authority. State credit ratings are significantly higher than IOUs with all but two states achieving a rating above AA- in 2012. In total there are 13 AAA, 15 AA+, and 16 AA rated states. Capital costs for infrastructure assets built using municipal bonds are low due to the tax-exempt status of the bonds as well as the securitized revenue streams that pay back the bonds.

Since the Tennessee Valley Authority (TVA) Act of 1933,[27] the federal government has taken a direct role in constructing transmission and distribution infrastructure in certain regions of the country. Along with TVA, the Department of Energy's four Power Marketing Administrations (PMAs) - the Bonneville Power Administration (BPA), the Western Area Power Administration (WAPA), the Southeastern Power Administration (SEPA), and the Southwestern Power Administration (SWPA) – market and distribute hydroelectric power produced at federal dams.[28] BPA, WAPA, and SWPA now collectively own and operate 33,700 miles of transmission lines, which are integrally linked with the transmission and distribution systems of utilities in 20 states.[29] While PMA power-related capital projects are financed primarily with appropriated funds, federal law requires power rates to be set at levels that will enable repayment of these appropriations albeit at very low rates.[30]

Cooperatives and the Public Role

Rural electric cooperatives (RECs) are consumer-owned utilities that were established to bring electricity to rural areas. These utilities are primarily located in rural areas where the return on expensive infrastructure investment was not high enough to attract the IOUs. RECs obtain power from public- or investor-owned power plants or by generating electricity themselves. Electric cooperatives also receive preference from the Federal PMAs. Excess power generated by Federal water projects is provided to cooperatives and public bodies at rates typically less than other sources.[31]

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[27] 16 U.S.C. 831
[28] U.S. DOE, SEPA, "A History of the Southeastern Power Administration," 2012
[29] U.S. DOE, "Power Marketing Administrations Poised to Make Another Big Contribution to America's Progress," March 16, 2012
[30] U.S. GAO, "Cost Recovery, Financing, and Comparison to Nonfederal Utilities," Testimony, September 19, 1996
[31] U.S. GAO, "The Evolution of Preference in Marketing Federal Power," February 2001.

The Rural Electrification Administration, established in 1935, provided early low-interest loans to rural electric utilities.[32] Over time the share of federal lending has declined; Rural Utility Service loans to electric cooperatives now comprise less than 40% of total financing. As part of the Build America Initiative, the USDA recently announced an additional $518m in loan guarantees available for rural utilities.[33] The remaining 60% comes from private sector sources such as the National Rural Utilities Cooperative Finance Corporation and the National Cooperative Services Corporation.

3.4) Barriers to Investment

Barriers to investment in electricity TS&D may include insufficient data, insufficient pricing transparency, risk aversion, project approval delays, cost allocation disagreements, and market or policy uncertainty. Lack of data and analytical tools have prevented quantification of the dollar value for improved reliability.[34] Electricity markets and rates often aggregate the cost of discrete services, such as energy, ramp rate, voltage, and capacity. Absent transparent price signals, developers, particularly for electricity storage, lack proper incentives to efficiently invest. Innovative new technologies can improve electricity reliability, efficiency, and economics, but utilities have exhibited risk aversion to deploying new technologies.[35] Major transmission lines can take several years to permit, which limits projects to entities with ample working capital. Debate during the planning process can also introduce delays, such as when costs for a new line are allocated to parties who may not benefit. Finally, the financial viability of new and existing renewable, nuclear, and coal generating capacity is highly uncertain due to the increased availability and low cost of natural gas and unpredictability of policy support for renewable generation (such as the Investment Tax Credit and Production Tax Credit). The resulting inability to plan for future generation increases the uncertainty surrounding transmission investment requirements.[36]

3.5) Regulatory Reforms Facilitate Utility Cost Recovery

At the state level, where distribution assets are regulated, general rate cases typically occur every 2-5 years.[37] This interval subjects the IOUs to additional risk due to the lag between the need for new assets and the ability to seek repayment from consumers. New regulatory policies that allow utilities to more rapidly recover investment expenditures include: capital expenditure cost trackers, construction work in progress, multiyear rate plans, revenue decoupling, retail formula rate plans, and forward test years. The types of policies approved by individual states are highly variable and can be either broad or specific regarding the types of infrastructure assets that qualify.

At the transmission level, the Federal Energy Regulatory Commission (FERC) Order 1000 facilitates inter-regional planning, clarifies cost allocation criteria, and opens the door to non-incumbent development. While these and previous reforms have attracted interest from new entities, the ability of

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[32] Executive Order 7037; Rural Electrification Act of 1936; 7 U.S.C. 904, 935
[33] White House, "Build America Infrastructure Investment Summit," Press Release, September 9, 2014
[34] Brattle, "Analysis of Benefits- PSE&G's Energy Strong Program," October 2013.
[35] Davide Savenije, "Three perspectives on the future of electric utilities," Utility Dive, February 11, 2014
[36] Brattle Group, Chupka, M.W., "Transforming America's Power Industry: The Investment Challenge 2010-2030," November 2008, http://www.edisonfoundation.net/IEE/Documents/Transforming_Americas_Power_Industry.pdf
[37] Regulatory Assistance Project, "Electricity Regulation In the US: A Guide," March 2011

transmission planning reforms to accelerate the deployment of capital for new transmission is still under evaluation.

4) Natural Gas and Liquid Fuels

The natural gas infrastructure network in the United States connects over 300,000 miles of transmission and over 2.1 million miles of distribution assets,[38] and about 419 underground natural gas storage facilities.[39] Pipelines are the dominant mode for petroleum transport in the United States, shipping approximately 71 percent of America's crude oil and petroleum products, and a much higher percentage of crude alone.[40] Over 180,000 miles of liquid petroleum pipelines[41] deliver more than 14 billion barrels annually of crude oil, petroleum products, and natural gas liquids,[42] each through their own dedicated pipeline network.[43]

Annual investments in oil and gas TS&D infrastructure increased 60 percent in just the three years between 2010 and 2013, from $56.3 billion to $89.6 billion, as the industry responded to the new energy landscape of increasing North American production and declining imports.[44] By 2025, the industry is expected to invest $890 billion in new infrastructure, with more than half expected to go to crude oil and natural gas gathering systems and direct production support facilities.[45]

4.1) Natural Gas Infrastructure Trends

The United States has seen $10 billion in average annual investments in midstream natural gas infrastructure over the past decade.[46] This included major pipeline projects that relieved constraints from Wyoming and from major shale basins in Texas, Oklahoma and Arkansas to Eastern markets. Between 2011 and 2035, industry has estimated that the United States may need an additional 35,000 miles of transmission main lines, which would require about $97 billion in capital expenditures.[47]

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[38] U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Annual Report Mileage for Gas Distribution Systems.
[39] EIA, Office of Oil and Gas, Natural Gas Division, Gas Transportation Information System, December 2008. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/undrgrndstor_map.html.
[40] "Other Means of Transport," Pipeline 101, http://www.pipeline101.org/why-do-we-need-pipelines/other-means-of-transport. Tankers and barges transport 22 percent of oil shipments. The remainder of shipments occurs via truck and rail (four percent and three percent respectively).
[41] "Where are the oil pipelines," American Petroleum Institute, http://api.org/oil-and-natural-gas-overview/transporting-oil-and-natural-gas/pipeline/where-are-the-oil-pipelines.
[42] "About Pipelines," Association of Oil Pipe Lines, http://www.aopl.org/pipeline-basics/about-pipelines/.
[43] Ibid.
[44] IHS Global Inc., *Oil & Natural Gas Transportation & Storage Infrastructure: Status, Trends, & Economic Benefits* (Washington, DC: American Petroleum Institute, 2013), http://www.api.org/news-and-media/news/newsitems/2014/jan-2014/~/media/Files/Policy/SOAE-2014/API-Infrastructure-Investment-Study.pdf.
[45] Ibid.
[46] ICF International, " North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance, " for the INGAA Foundation, March 2014. http://www.ingaa.org/Foundation/Foundation-Reports/2035Report.aspx.
[47] Ibid.

Shale Gas is a Major Driver for New Investments

Some natural gas has been produced from shale formations since the 19th century, but the amounts were fairly small – about 5 percent of the United States total in 2004. Since then, shale gas production in the United States has grown more than tenfold from 2.7 billion cubic feet per day (Bcf/d) in January 2004 to about 35 Bcf/d in May 2014 (Figure 6); at the same time, conventional gas production has fallen over the same period, by about 14 Bcf/d. The result is an overall growth in production of about 18 Bcf/d, with shale gas now accounting for about half of overall gas production. New pipelines have been constructed to bring some of the new supplies to market. EIA estimates that between 2004 and 2013, the natural gas industry spent about $56 billion expanding the natural gas pipeline grid.[48]

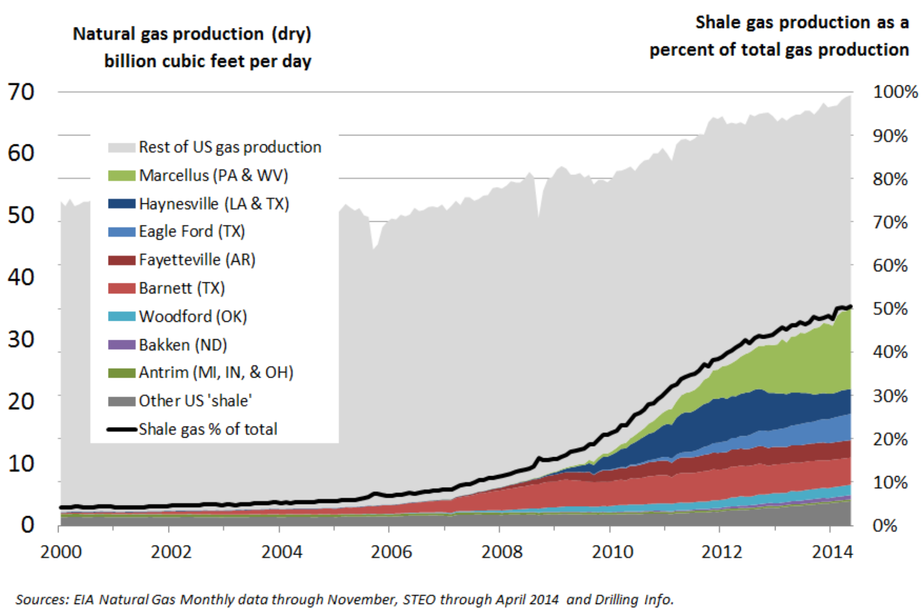

Figure 6: Gas production from various regions and US

The availability of shale gas has contributed a 35 percent rise in dry natural gas production between 2005 and 2013, about a 55 percent fall in average annual spot natural gas prices, and an approximately 39 percent increase in the use of natural gas to generate electric power.[49]

Natural gas storage facilities help balance daily and seasonal changes in natural gas supply and demand. The increase in demand for natural gas for electric power generation has led to growing interest in high-deliverability gas storage, typically provided by peak load storage facilities.

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[48] Based on analysis from EIA data, http://www.eia.gov/naturalgas/data.cfm#pipelines.
[49] DOE QER Task Force Secretariat, "Stakeholder Meeting on Natural Gas Transmission, Storage and Distribution," July 17, 2014

Other Drivers for Natural Gas Investment

As late as the mid-2000s, the U.S. was expected to import liquefied natural gas (LNG). American gas producers now expect to start exporting LNG from the Sabine Pass terminal in Louisiana as soon as late 2015. Many overseas importers believe U.S. gas exports will act as a counterpoint to oil-linked prices prevalent abroad and potentially exert significant downward pressure on global LNG prices.[50]

Asset replacement is also a driver of investment. More than 50 percent of the nation's gas transmission and gathering pipelines were constructed in the 1950s and 1960s, during the post-WWII economic boom.[51] Approximately 3 percent of gas distribution mains are made of rapidly deteriorating cast iron or wrought iron. These assets may need replacement or refurbishment to reduce safety risks and leakages.

4.2) Liquid Fuels Infrastructure Trends

Since 2008, U.S. oil production has grown rapidly, reaching more than 8.4 million barrels per day (MMBbl/d) in April of 2014.[52] The domestic oil boom is due primarily to new production of light sweet crude from unconventional tight-oil formations in North Dakota (Bakken) and Texas (Eagle Ford and Permian Basin), using the same technologies that propelled U.S. shale gas production.[53] Together, these two states now account for nearly half of total domestic crude production.

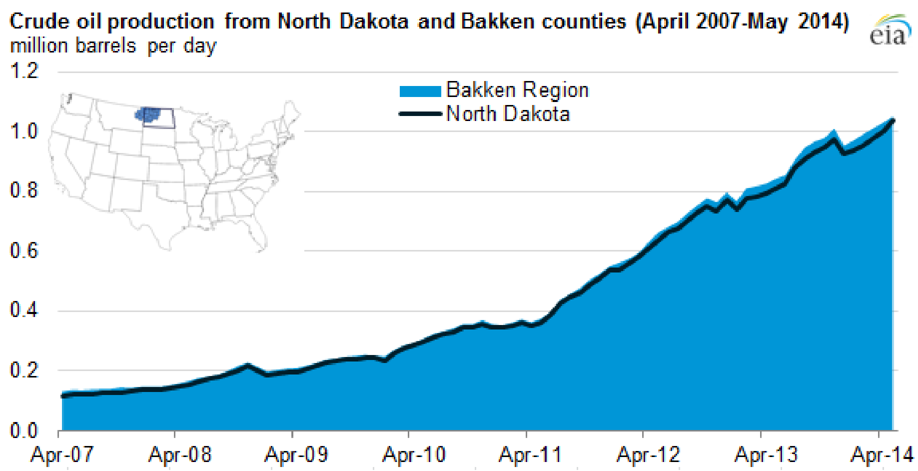

Figure 7: North Dakota crude oil production surpassed 1.0 million barrels per day (bbl./d) in April and May 2014[54]

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[50] Johnson, K. and LeFebvre, B., (2013, May 18). U.S. Approves Expanded Gas Exports. *The Wall Street Journal*. Retrieved from http://online.wsj.com/news/articles/SB10001424127887324767004578489130300876450.

[51] U.S. Department of Transportation, *The State of the National Pipeline Infrastructure*, Washington, DC, 2011

[52] U.S. Energy Information Administration (EIA), "Petroleum Supply Monthly – Daily Average," April 2014, http://www.eia.gov/dnav/pet/pet_sum_snd_d_nus_mbblpd_m_cur.htm.

[53] U.S. EIA, "Shale Gas Production," April 10, 2014, http://www.eia.gov/dnav/ng/ng_prod_shalegas_s1_a.htm.

[54] EIA, "Bakken Fuels North Dakota's Oil Production Growth," *Today in Energy*, August 4, 2014

Historically, the town of Cushing, Oklahoma has hosted the North American midcontinent hub for oil distribution—mostly crude originating from West Texas production or crude oil imported to the U.S. Gulf Coast and shipped north via pipeline. Until recently, U.S. oil pipeline construction and system configuration has roughly mirrored this traditional flow pattern, facilitating crude movements to U.S. refineries located throughout the Midwest. These flow patterns are now shifting, as Canadian oil sands and U.S. tight oil production has soared over the last few years. In the midcontinent hub in Cushing, growth and growing congestion have created a bottleneck. To relieve the resulting pressure, energy firms and other market participants have invested in reconfigured and expanding petroleum pipeline infrastructure (as well as crude-by-rail infrastructure), enabling the southward flow of North American crude to refineries based along the U.S. Gulf Coast. For example, flow along the Seaway pipeline was reversed and now moves crude oil from Cushing down to Houston, Texas. The initial reversal cost $300 million, with an expected addition cost of $2 billion for ongoing expansion to bring capacity to 850,000 barrels per day (bpd) by mid-2014.[55] In the Gulf Region, the 350-mile Ho-Ho line used to move imported oil from Houma, Louisiana, to Houston, Texas, but now brings crude from the Eagle Ford and Bakken plays to refineries on the Gulf Coast.[56]

4.3) Alternatives and Tradeoffs for Liquid Fuel Transmission

The increase in domestic petroleum production has outpaced construction of new pipelines and allowed non-pipeline transmission alternatives to carve out a foothold in the market. The emergence of rail as a significant mode of crude transport highlights not only a regional constraint in pipeline infrastructure but also the petroleum industry's increasing willingness to search out and invest heavily in alternatives. Between 2008 and 2013, oil rail transport has increased from 9,500 to over 400,000 carloads per year.[57]

In addition to pipelines and rail, barges and trucks add to the range of options with trade-offs between cost, speed, volume, safety, and general optionality, typically depending on location and application. These tradeoffs can change through investment and policy actions. For example, rail transport of crude is disadvantaged in its overall shipping cost of $10 to $15 per barrel, compared to approximately $5 cost per barrel for pipelines.[58] However, rail has an established infrastructure and generally requires construction of only loading and unloading facilities. Rail infrastructure services every refinery in the country, and rail and related facilities can be built more quickly than pipelines and refineries, allowing them to keep pace with production growth.[59] Consequently, rail offers oil producers greater flexibility, rapid response to

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[55] Reuters, "FACTBOX-U.S. oil pipeline projects," *Chicago Tribune*, May 31, 2013, http://articles.chicagotribune.com/2013-05-31/news/sns-rt-usa-pipelineoil-factboxl2n0ec1r6-20130531_1_eagle-ford-shale-oil-pipeline-enbridge-inc-origin-destination.
[56] Matthew Monks, "Shell Said to Seek Buyers for $1 Billion Stake in Ho-Ho Pipeline," *Bloomberg*, January 27, 2014, http://www.bloomberg.com/news/2014-01-27/shell-said-to-seek-buyers-for-1-billion-stake-in-ho-ho-pipeline.html.
[57] American Association of Railroads, *Moving Crude Oil by Rail.* (Washington, DC: American Association of Railroads, September 2014). https://www.aar.org/keyissues/Documents/Background-Papers/Crude-oil-by-rail.pdf
[58] Department of State, Keystone XL Final Supplemental Environmental Impact Statement, Appendix C, Supplemental Information to Market Analyses, Table C1 and the attached ICF report., and Department of State, Draft Supplemental Environmental Impact Statement, Appendix C, Tables 3, 4, and 5.
[59] Association of American Railroads, *Moving Crude Oil by Rail* (Washington, DC: Association of American Railroads, December 2013), https://www.aar.org/keyissues/Documents/Background-Papers/Crude-oil-by-rail.pdf.

market changes, and fewer capital risks. However, there is increasing public safety concern about rail as a mode of oil transportation.

Barge transport has also played a role in moving new Canadian and U.S. crude oil production to refineries and markets. Barge transport can compete with pipelines where water access is reasonably direct and often entails an intermodal exchange.

4.4) Midstream Ownership Structures and Financing

Prior to the deregulation of the 1980s, natural gas exploration and production companies would drill for natural gas and sell it from the wellhead to pipeline companies. Pipeline companies would sell the natural gas to local distribution companies (LDCs), which would distribute and sell gas to their customers.

Today, midstream natural gas and liquids assets (e.g., interstate and intrastate pipelines, storage, compression, etc.) are generally paid for by long-term take-or-pay contracts where shippers reserve capacity on the pipeline and pay demand charges independent of whether capacity is actually utilized. The transportation rate an interstate natural gas pipeline charges a customer can be one of the following: the maximum rate allowable by the Federal Energy Regulatory Commission (FERC), which is based on the pipeline's average cost of providing service; a discounted rate from the maximum rate; a market-based rate, or a negotiated rate between the pipeline and the shipper.

Natural gas and liquid fuels transmission assets are often entirely owned by non-utility entities. The rates charged by these midstream transmission companies do not require public regulatory commission approval. Rather, FERC mandates the use of an open season, where customers competitively bid for the rights to use pipeline capacity.

Midstream assets, as defined by their tax-filing status, can be owned by a standard C-corporation, a limited liability company (LLC) or a master limited partnership (MLP). Currently, the dominant form of ownership is the MLP with approximately $445 billion dollars of market value in 2013.[60]

4.5) Master Limited Partnerships

A Master Limited Partnership (MLP) is an entity whose profits and losses are passed onto limited partners, without taxation at the entity level. To qualify for MLP status, a partnership must generate at least 90 percent of its income from what the Internal Revenue Service (IRS) deems "qualifying" sources,[61] which include activities related to the production, processing and transportation of oil, natural gas and coal. Due to the nature of the quarterly required distributions, the vast majority of MLPs are pipeline businesses, which earn stable income. This model has become increasingly common for financing midstream oil and gas infrastructure investments.

The number of energy MLPs has increased from 6 in 1994 to 107 in 2013. The total market capitalization of the energy MLP universe has grown from approximately $2 billion in 1994 to roughly $445 billion in

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[60] Wells Fargo MLP Primer Fifth Edition: A Guide To Everything MLP, Well Fargo Securities, October 31, 2013, pg. 9.
[61] Internal Revenue Code (IRC) Section 7704(d)(1)(E)

2013.[62] Over that time period, the average market cap of a publicly traded MLP has increased from $297 million to $4.2 billion. While MLPs are still predominantly owned by retail investors, institutional investor interest in the sector has increased as investors focus on income-oriented securities. The median MLP yield is currently 6.5%, which compares favorably to other income-oriented investments.

While there has been a significant growth of MLPs, recent events illustrate that the MLP model may have limits. Kinder Morgan recently consolidated its partnership ventures – currently trading as master limited partnerships (MLPs) – into a single non-MLP entity that is the largest pipeline company in the United States.

4.6) Barriers to Natural Gas Investment

Barriers to natural gas investment include externalities and structural incompatibility. Recovering investments for natural gas infrastructure improvements in heavily cost regulated markets is a challenge, in part because the market value of the natural gas does not reflect, among other things, the externality value of climate and environmental impacts from gas leakage. Contracts for firm gas transmission capacity are essential to securing financing for new transmission pipeline infrastructure. Even as gas demand for power production rises, gas transmission companies struggle to conclude contracts, in part because electricity market rules are not compatible with the financing requirements pipelines face for proceeding with new investment. The uncertainty in the size of the LNG export market also propagates into uncertainty in midstream investment.

4.7) Reforms in Rate-Based Assets

According to a 2012 report, the use of advanced regulatory mechanisms that allow natural gas utilities to recover costs of utility replacement between rate cases has tripled in the last five years.[63,64] As in the electric industry, construction work in progress, cost trackers, rate and revenue caps, revenue decoupling, formula rate plans, and forward test years are potential tools to mitigate or avoid rate shock, removing barriers to new investment, providing access to capital, and increasing construction and operation efficiency.[65] However, these ratemaking approaches are confined within the traditional utility cost of service model. They do not tend to reduce the underlying cost of financing of infrastructure investments, but instead allocate the cost over time.

5) Alternative Finance Strategies for Energy TS&D Infrastructure

Although financing electric transmission, storage, and distribution infrastructure has traditionally been executed using corporate, public, or project financing, there are efforts to utilize alternative financing methods. The past several years have seen the emergence of new or growing finance structures and

[62] Wells Fargo Ibid, pg. 9
[63] American Gas Association. To Encourage Infrastructure Investment, More States Are Allowing Innovative Utility Rate Designs, Foster Natural Gas/Oil Report. 2012
[64] Atamturk and Zafar, "Trends in Utility Infrastructure Financing," CPUC, August 2012
[65] Owens, D.K. "New Regulatory Frameworks Encourage Electric Infrastructure Investment, Public Utilities Fortnightly". 2011

applications across the energy sector, including Real Estate Investment Trusts (REITs), Green Bonds, and State Infrastructure/Green Banks.

5.1) Real Estate Investment Trusts

A real estate investment trust (REIT) is a company that owns, and in most cases, operates income-producing real estate. REITs own many types of commercial real estate, ranging from office and apartment buildings to warehouses, hospitals, shopping centers, hotels and timberlands. REITs were designed to provide a real estate investment structure similar to the structure mutual funds provide for investment in stocks. Congress created REITs to give all investors the opportunity to invest in large-scale, diversified portfolios of income-producing real estate in the same way they typically invest in other asset classes – through the purchase and sale of liquid securities. In addition, infrastructure assets are attractive to private investors and perceived by investors as a means to diversify investment portfolios and as hedges against inflation and interest rates.[66]

REITs are not subject to federal taxes as long as 90% of taxable income is distributed to investors in the form of dividends. This company structure can be publicly or privately held, but the type of asset included in the REIT must be approved by the Internal Revenue Service (IRS). In 2007, the IRS issued a private letter ruling that approved REIT formation for electric transmission and distribution assets held by Sharyland Distribution and Transmission Services LLP (Sharyland D&T) in Texas.[67,68] Upon approval, Sharyland D&T sold transmission and distribution assets to the Electric Infrastructure Alliance of America (EIAA), the private REIT entity. Sharyland Utilities now leases the T&D assets from EIAA and continues to perform normal operations. With up to $2.1 billion in capital raised from selling the T&D assets, Sharyland D&T is in a position to invest in additional infrastructure while investors can make a profit from owning a portion of the EIAA REIT.

Although the first of this class of alternative finance has been successfully executed and others are pursuing a similar strategy, REIT formation may face resistance from regulated utility companies. REITs move assets out of the rate base and remove the opportunity to earn a rate of return on those assets. In a survey of large transmission owners 100% of the 30 respondents expressed fear that regulators would not share the benefit and 84% expressed no desire to sell their assets.[69] On the other hand, a REIT structure may minimize capital demands on the utility while helping avoid development, construction, technology, and regulatory risk.

5.2) Green Bonds

Corporate bonds remain a major source of financing for transmission, storage, and distribution infrastructure. Recently, green bonds have been introduced as a way for investors to finance environmentally friendly infrastructure. A consortium of major banks introduced the "Green Bond

[66] Weisdorf, M. A. Infrastructure: A Growing Real Return Asset Class, CFA Institute. 2007
[67] IRS Private ruling letter 200725015 http://www.irs.gov/pub/irs-wd/0725015.pdf
[68] Sharyland Utilities, "History of Sharyland Utilities," Downloaded September 2014 http://www.infrareitcp.com/overview.html
[69] California Public Utilities Commission. Trends in Utility Infrastructure Financing. August 2012.

Principles" in January of 2014,[70] which are intended to provide transparency to the market. The green bond market has grown from roughly $1 billion in 2008 and is expected to exceed $40 billion in 2014.[71]

In addition to corporate bonds, the green bond market also includes project bonds. Transmission assets qualify as a green investment, as illustrated by the $496 billion dollar bond issued for the Greater Gabbard transmission line in the UK. This line transfers energy from offshore wind generation assets. Although this example is outside the US, similar projects within the US could be structured within the newly competitive transmission procurement provisions of FERC Order 1000. The green bond market is widely expected to grow over the next decade and may provide a significant new source of capital for electric transmission, storage, and distribution infrastructure.

5.3) State Infrastructure Banks and Green Banks

Infrastructure projects are often financed through the use of State or Federal programs that broadly fall under the classification of State Revolving Funds (SRF). SRF programs provide infrastructure projects with low cost financing in the form of loans and loan guarantees. These programs can require co-participation from private capital markets. Public capital is provided by both State and Federal investments in the case of State Infrastructure Banks (SIB) or by State investments alone for State Infrastructure Revolving Loan Funds (SRF) and State Green Banks (SGB)[72]. While SRF/SIB are often dedicated to water and transportation infrastructure, SGBs such as the New York Green Bank as well as Connecticut's Clean Energy Finance and Investment Authority (CEFIA) support clean energy infrastructure. SGBs can employ direct lending, co-lending with outside lenders, credit enhancements to reduce the cost of capital, or pooling and securitization of project loans to allow greater access to debt capital markets[73].

6) Request for Comments

QER staff request comment on how the historic role of private investment can be maintained and focused while meeting new challenges and opportunities in energy. Commenters are invited to provide insight on the criteria for bankable projects, outlining the attributes that enhance or detract from the desire of an investor to provide financing, and how the federal government can help reduce barriers to finance. Commenters are also invited to comment on the role of alternative structures or applications, such as infrastructure banks. Finally, a list of key questions has been included to help guide further input.

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[70] JP Morgan Chase, "Expanding Bond Market for Green Projects," http://www.jpmorganchase.com/corporate-responsibility/green-bonds
[71] BNEF, "Green Bonds Market Outlook 2014," June 5, 2014 http://about.bnef.com/white-papers/green-bonds-market-outlook-2014
[72] Brookings Institute. Banking on Infrastructure: Enhancing State Revolving Funds for Transportation. 2012
[73] Brookings Institute. State Clean Energy Finance Banks: New Investment Facilities for Clean Energy Development. 2012

KEY QUESTIONS

Attracting and maintaining capital for energy transmission, storage, and distribution

1. How do investors and capital markets view energy TS&D infrastructure as an asset class, especially compared to other sectors?
2. Given the need for additional energy infrastructure investment, is there a limitation to the supply of capital or a lack of attractive projects?
3. What are the implications of current low interest rates and potential future changes for investing in energy TS&D infrastructure now vs. later?
4. How can the investor, policy, and energy communities collaborate to reduce risk, increase the rate of return, or otherwise facilitate financing of electricity, natural gas, and liquid fuels infrastructure?
5. Where can the federal government be effective in reducing barriers to capital flow to needed energy TS&D infrastructure?
6. How can governmental informational policy levers (e.g., standards, data, planning) de-risk new TS&D assets from investors' points of view?
7. What are historic drivers of utility credit ratings and how are those likely to change in the future? What do these changes imply about how finance will flow to energy infrastructure?

Bankability of electricity TS&D infrastructure

8. In an era of declining or negative demand, how do TS&D owners view corporate growth and plan for needed upgrades?
9. How should functional services (such as resiliency or ancillary services) and externalities (such as climate risk) be evaluated, priced, and compensated?
10. How can new financing applications or structures accelerate development of needed TS&D infrastructure (e.g. REITS, Green Bonds, Infrastructure Banks)? What potential changes in tax status could affect investment in needed TS&D infrastructure?

Opportunities and challenges for natural gas and liquid fuels TS&D infrastructure

11. How should returns be balanced with the ability of ratepayers to absorb increasing system needs, such as leaking distribution systems or resiliency upgrades?
12. How have LNG export, increased demand from electricity generation, and other external challenges altered the landscape for pipeline and storage investment?
13. What is the role of corporate structures (such as MLPs and REITs) for TS&D under scenarios of growth or uncertainty for natural gas and liquid fuels delivery infrastructure?