Q. Coyne Evidence – Attachment 1, p. A-4: Please provide a copy of Mr. Coyne's white paper in relation to regulatory and utility responses to a low carbon world.

A. Please see Attachment A to this response.

White Paper

June 2, 2010

Moving to a Lower Carbon World: Implications for Energy Utilities and Regulation

Abstract

Public concerns for environmental sustainability, economic prosperity and regional security have converged in the debate over when and how to reduce greenhouse gas (GHG) emissions. No matter their form, GHG policies will require a significant reduction in the level and forms of traditional fossil fuel consumption. Hence, GHG policies will drive a transformation of the traditional energy utility business model (i.e., energy supply and commodity delivery) to a model of the utility as an enabler and integrator of diverse energy services. Potentially three utility grids will evolve: electric, gas, and heat and become more integrated, centered on combined heating and power resources serving urban centers. To facilitate these developments, cohesive public policy direction from federal, provincial and municipal government is required. Industry must be prepared to make the necessary investments in research, development, and new technology deployment. Regulators will be required to implement broad policy directives, allowing the market to choose winners and losers in the competition for innovative and efficient solutions. Determinations must nonetheless be made on which services should be provided by competitive vs. regulated service providers, and how transition costs should be borne. The boundary between competitive and monopoly services will shift over time as the market matures. Consequently, utility transformation and regulatory transformation must move forward interdependently.

This paper explores several key questions associated with industry transformation:

1. What are the practical implications of the fluid GHG and energy policy agenda?
    - Without policy clarity, how is the public interest to be determined?
    - Wait for policy clarity or pursue a path of compliance with anticipated policies?
    - What are the downsides and upsides of getting out in front of policy?

2. How will GHG reduction mandates impact gas and electric markets?
    - Supply and demand shifts
    - Areas of market growth
    - Declining or displaced markets

3. How will pursuit of GHG reduction goals affect the traditional energy delivery utility business model?
    - New services and investment requirements
    - New competitors or business partners
    - Existing and future customer relationships

4. What types of regulatory changes may be needed to accommodate changing utility business models? What are the key issues that regulators will likely need to resolve to reach common strategic ground with utilities?
    - Determination of competitive (unregulated) vs. utility (regulated) services
    - Rate design and cost recovery mechanisms
    - Which parties assume responsibility for energy service reliability?

The paper reaches the following conclusions:

- Once GHG regulation is established, the cost of carbon will be quantifiable and can be explicitly accommodated in existing utility regulatory practices. While traditional regulatory practices and structures are sufficiently flexible to accommodate utility business model transformation, a critically important element of successful transformation will be the coordination of business strategy and regulatory policy, particularly with respect to assumption of business risks, responsibility for service reliability, and role of regulated versus unregulated service providers.
- Driven by GHG reduction mandates, the energy delivery utility business model will transition towards a smart energy network model that integrates energy supply and demand resources to optimize the production, delivery and consumption of energy in a much more dynamic and decentralized manner than today's separate electricity and gas utility systems. Smart energy networks allow greater flexibility in matching energy supply with demand, and the deployment of distributed generation and CHP resources throughout the grid will mark the blurring of the notions of traditional energy utility supply (i.e., remote upstream) and demand (i.e., local downstream) resources.
- As the transformation process unfolds, the resulting business models will be unique to each utility, as each crafts a strategy that suits its specific market, energy sources, risk tolerance, innovation, and regulatory/political environment. Transformation will take many years, and may never reach many customers that remain reliant on traditional utility services. To avoid management distraction from the traditional core utility mission of maintaining high quality, low cost and reliable traditional electric and gas delivery services for all customers, utilities may elect to pursue new services via a separate unregulated company. Utilities face a critical initial strategic decision: (i) compete in the integrated energy delivery services market on a regulated basis; or (ii) create an unregulated affiliated company to compete for integrated energy delivery services or a combination of the two.
- Government forecasts anticipate that GHG policies will affect both wholesale and retail energy markets. At the wholesale level, one key impact, most notably in Ontario, is to phase out coal-fired generation. At the retail level, energy efficiency, on-site renewable energy, and provincial carbon taxes are forecast to trigger a decrease in gas and electric energy intensity, but limited structural shifts in end-use applications.
- The greatest barrier to industry transformation will be securing public acceptance of large energy cost increases. Failure of GHG policymakers to account for these costs and the public's response to them poses serious financial and political risks for utilities and regulators. Regulators and utilities share the responsibility to educate policymakers on the business implications of GHG policies, including providing a realistic estimate of the scale of investment required to transform the traditional utility business model.

This paper draws upon the themes initiated during the February 25-26th Regulator/ Industry Dialogue in Toronto and is designed to focus that discussion and illustrate examples of potential solutions. Some of these themes also emerged from the CAMPUT conference "Toward Sustainable Regulation" held in Montreal over May 2-5, 2010. The envisioned industry evolution will hopefully serve as a "strawman" for further discussion and refinement.

Moving to a Lower Carbon World: Implications for Energy Utilities and Regulation

Public concerns for environmental sustainability, economic prosperity and regional security have converged in the debate over when and how to reduce greenhouse gas (GHG) emissions. No matter their form, GHG policies will require a significant reduction in the level and forms of traditional fossil fuel consumption. Hence, GHG policies will drive a transformation of the traditional energy utility business model (i.e., energy supply and commodity delivery) to a model of the utility as an enabler and integrator of diverse energy services. Potentially three utility grids will evolve: electric, gas, and heat and become more integrated, centered on combined heating and power resources serving urban centers. To facilitate these developments, cohesive public policy direction from federal, provincial and municipal government is required. Industry must be prepared to make the necessary investments in research, development, and new technology deployment. Regulators will be required to implement broad policy directives, allowing the market to choose winners and losers in the competition for innovative and efficient solutions. Determinations must nonetheless be made on which services should be provided by competitive vs. regulated service providers, and how transition costs should be borne. The boundary between competitive and monopoly services will shift over time as the market matures. Consequently, utility transformation and regulatory transformation must move forward interdependently.

The Toronto Regulator/ Industry Dialogue reviewed the fluid state of North American GHG policy development. The U.S. continues to struggle to define a unified national voice of GHG policy and Canada remains a GHG "policy taker". At the same time, certain states, provinces and municipalities are attempting to fill the federal policy voids by developing a wide variety of GHG policies, acting either autonomously or in cooperation with other governments or non-governmental actors. Dialogue participants expressed a clear preference for greater coordination of government GHG policy initiatives, but recognized there will be a prolonged period of GHG policy uncertainty.

This paper does not attempt to predict future specific Canadian or U.S. GHG policies. Rather, it presumes that regulated electricity and natural gas delivery utilities will need to comply with federal and/or provincial GHG emission reduction goals (e.g., 17% reduction by 2020 and 60-70% by 2050). Indeed the persistence of high unemployment rates, continued government deficits with a correspondingly higher tax burden on consumers, and significant world events (BP oil fiasco, increased terrorism, clean water crises) could result in a significant delay in addressing GHG reductions. Consequently, the regulator/industry dialogue is even more important, as the energy policy makers may be focused on or overtaken by other issues. Within this policy context, the paper explores several key business and regulatory implications associated with the industry changes required to accommodate these objectives.

1. <u>What are the practical implications of the fluid GHG and energy policy agenda?</u>

The Dialogue examined how regulators can hold diverse views of what is the public interest in the transformation to a lower carbon world, characterized as:

- Activist – Regulators view carbon reduction as a fundamental part of the public interest in regulating energy utilities
- Efficient – Regulators take climate policy as given and try to achieve the least costly system for the entire economy over time
- Traditional – Regulators focus on low rates and reliability in the short and medium run

This framework provides a spectrum of potential regulatory responses in an environment marked by long-term carbon policy uncertainty. For example, Activist regulators anticipate near-term carbon mandates and take actions designed to secure near-term carbon emission reductions, but risk imposing unnecessary or premature energy costs on consumers if legislators fail to act. At the other extreme, Traditionalists see no current carbon regulations and resist taking such actions, but risk burdening ratepayers with stranded investments or higher compliance costs if legislators adopt significant near-term carbon reduction requirements. Given the long-term investment risk embedded in both approaches, regulators need to reach out proactively to legislators to clarify the public interest concerning regulatory strategy for carbon emission reductions. Utility regulators also need to develop a much closer relationship with energy and environmental regulators to define clearer objectives and mechanisms for implementation. Failure to clarify the public interest risks strategy misalignment between regulators, utilities, ratepayers and politicians, resulting in a protracted, confusing and expensive oscillation between regulatory policies. The widely varying approach to GHG policy development at the provincial level will only magnify this misalignment and emphasizes the importance of a coordinated and proactive response by regulators to address GHG policy uncertainty.

2. <u>How will GHG reduction mandates impact gas and electric markets?</u>

The general impacts of lower GHG emissions have been considered in several studies. Natural Resources Canada's most recent energy market forecast[1] excludes any federal government program that had not been adopted by 2006; hence it reflects no GHG reduction policies or programs. The NEB's most recent energy market forecast[2] notes that federal and provincial GHG reduction policies under consideration have the potential to impact both the demand for and price of natural gas and electricity. However, recognizing the current state of carbon policy uncertainty, the NEB elected to incorporate in its forecast analysis only those policies currently in effect:

> "These policy directives are noteworthy and provide an outlook of potential future directions. However, many of these policies are not yet at the program stage. The 2009 Reference Case Scenario includes only current government programs in its analysis, therefore the evolving policies, such as those mentioned above, have not been quantitatively analyzed. Policies such as cap and trade programs and low carbon fuel standards have been commented on within this report in the emerging trends discussions. This aligns well with the standard methodology

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1 Canada's Energy Outlook: The Reference Case 2006.

2 NEB: 2009 Reference Case Scenario: Canadian Energy Demand and Supply to 2020 An Energy Market Assessment July 2009.

> employed by other groups, such as the U.S. Energy Information Agency." *[NEB 2009 Reference Case Scenario, pg. 4]*
>
> "One of the biggest challenges of this report is the implementation of several key policies at the federal level that are not yet final. Although in the development stage, they are lacking in sufficient detail to be properly modeled in the Reference Case Scenario." *[NEB, pg. 17]*

The NEB forecasts that currently effective GHG policies will affect both wholesale and retail energy markets. At the wholesale level, the principal policy driver is the initiative, most notably in Ontario, to phase out coal fired generation and the recent announcements by the Federal Government regarding new "equivalent to natural gas" emissions standards for coal-fired power generation. By 2020, the NEB forecasts annual electricity generation from coal to decline significantly, while other resources expand, as depicted in the following table:

Forecast Electricity Generation (2008-2020)		
Resource Type		**Change in Annual Generation ('08-'20)**
Hydro		13%
Coal		-46%
Nuclear		30%
Natural Gas		63%
Wind		566%
Other Renewables		139%
Source: NEB 2009 Reference Case Scenario (pgs 34-37)		

At the retail level, the forecast incorporates current federal and provincial programs designed to increase end-use energy efficiency (e.g., building codes and appliance standards), promote on-site renewable energy, and carbon taxes in British Columbia and Québec. Over the ten year forecast period this results in a lowering of gas and electric energy intensity, but limited structural shifts in end-use applications (e.g., rapid adoption of district heating or reduction in electric heating). Complicating the picture, the NEB observes that the decline in energy intensity is offset somewhat by increased penetration of electric end-use applications, particularly in the residential sector, and the demand rebound effect enabled or stimulated by increased energy efficiency.

The U.S. Energy Information Administration ("EIA") has adopted a similar analytic approach in its most recent energy market forecast, the Annual Energy Outlook ("AEO") 2010 Reference Case. The EIA assumes the continuation of current laws and regulations and excludes potential future laws and regulations, including those addressing GHG emissions. For the electricity sector, EIA is forecasting an expansion of renewable energy driven by state RPS programs and lower growth in electricity demand due to federal and state energy efficiency initiatives. In 2009, EIA analyzed the impact of the American Clean Energy and Security Act ("ACESA") passed by the U.S. House of Representatives in

June 2009.[3] The ACESA includes several GHG emission and energy provisions including a GHG cap and trade program, a national clean energy portfolio standard for electricity sellers, a carbon capture and storage ("CCS") demonstration and deployment program, and new federal building code and appliance energy efficiency standards. For the electricity sector, EIA concluded that the ACESA would result in lower conventional coal and natural gas generation, higher renewable, nuclear and CCS generation, and reduced demand relative to EIA's 2009 AEO reference case forecast. EIA also concluded that the ACESA would result in aggregate economy-wide gas demand to decline by nearly 3% relative to the 2009 AEO reference case.[4]

3. <u>How will pursuit of emission reduction goals affect the traditional energy delivery utility business model?</u>

The following table presents current provincial GHG reduction goals for 2020:

Province	2020 GHG Reduction Target
AB	58% above 1990 levels
BC	33% below 2007 levels
MB	6% below 1990 levels
NB	10% below 1990 levels
NL	10% below 1990 levels
NS	10% below 1990 levels
ON	15% below 1990 levels
PE	10% below 1990 levels
QC	20% below 1990 levels
SK	20% below 2006 levels
YT	Become carbon neutral

When considering these goals, Dialogue participants recognized that achieving them will require:

- Unprecedented levels of end-use energy efficiency, new energy technologies, and new energy services; and
- A transformation of the traditional energy delivery utility business model so that the utility serves as an enabler and integrator of diverse energy services including: energy efficiency, emerging "smart grid" network technologies, integrated community combined heating and power, distributed electric generation, and electric vehicles.

Central to this business model is the development of a smart energy network that integrates diverse energy supply and demand resources to optimize the production, delivery and consumption of energy in a much more dynamic and decentralized manner than today's separate electricity and gas utility systems. Smart energy networks allow greater flexibility in matching energy supply with demand, and the deployment of distributed generation and CHP resources throughout the grid will mark the

[3] EIA: Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009; August 2009.

[4] EIA: Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009; August 2009; Table ES-1, pg. xi.

blurring of the notions of traditional energy utility supply (i.e., remote upstream) and demand (i.e., local downstream) resources. QUEST (Quality Urban Energy Systems of Tomorrow)[5] provides one perspective on the future energy delivery services business model. This vision is based on six core principles to guide the development of integrated, sustainable and highly efficient urban energy systems in Canadian communities:

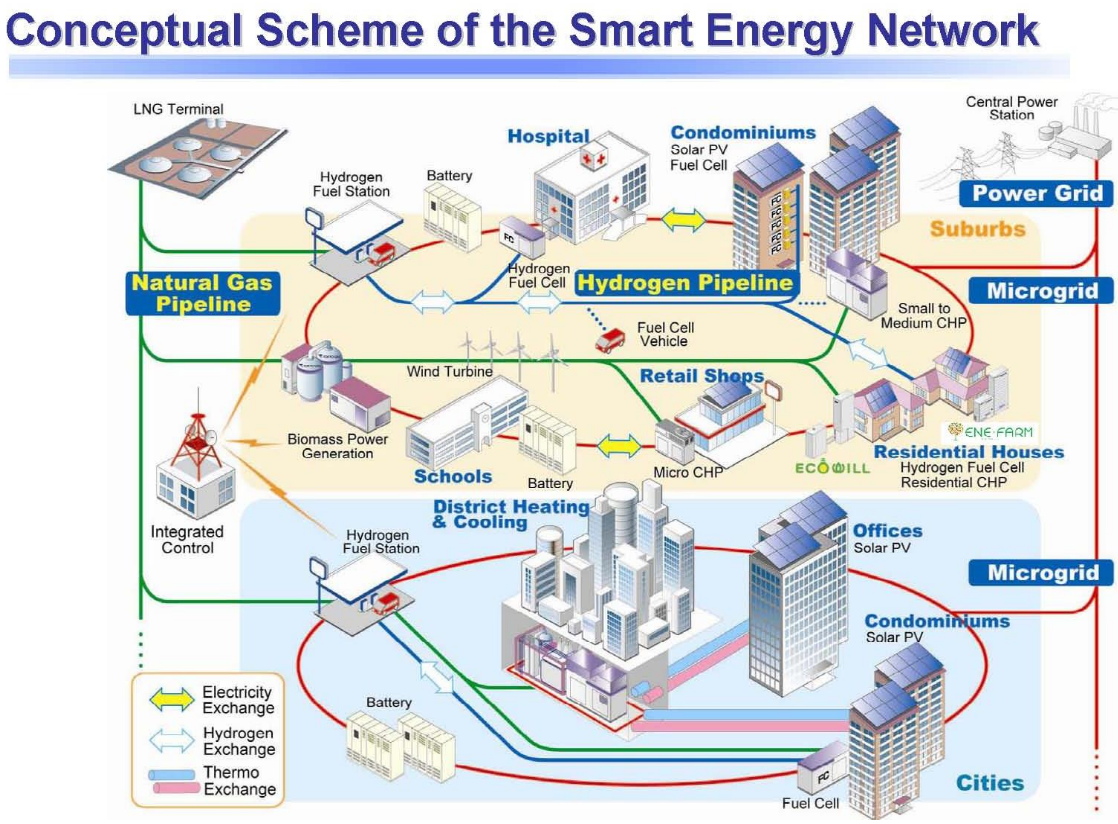
1. Improve efficiency
2. Optimize energy (avoid using high quality energy in low-quality applications)
3. Manage heat (capture and use all feasible thermal energy)
4. Reduce waste (use all available resources, e.g., landfill gas, gas pressure drops, biowaste, etc.)
5. Use local renewable resources
6. Use the grid strategically (optimize use of gas and electric grids and maintain reliability)

The QUEST concept suggests the development of new business models for energy delivery utilities. The value-added roles for utilities would include:

- Exploit their operational and financial capacity to connect alternative energy sources while providing peaking or backup supply to ensure service and grid reliability;
- Partner with developers and existing building owners to develop multiple smaller scale urban energy systems, located closer to and within buildings, integrated with elements of buildings, and integrated with other infrastructure systems. ;
- In partnership with municipalities or large commercial developments, fund and implement pilot, demonstration and showcase projects, e.g., micro-utilities, on-site distributed generation, electric vehicles;
- Utilize the distribution grid and gas purification technology to harvest, market and distribute local renewable gas sources.

In the Natural Gas Technology Futures Workshop sponsored by the CGA earlier this year, participants explored energy technology and service applications that extend the vision of an integrated and dynamic energy grid well beyond the QUEST model. As depicted below, representatives of the Japanese gas industry depicted a smart energy network model that includes a hydrogen-based infrastructure dynamically integrated into gas and electricity grids through a network of combined heat and power, district energy and distributed renewable and fuel cell applications. An integrated IT and communications backbone enables this smart energy network and allows a redefinition of traditional notions of energy supply and demand resources.

[5] QUEST is a collaborative of entities from industry, the environmental movement, governments, academia and the consulting community that recognize that accomplishing GHG reduction goals will require Canada to move beyond controlling or pricing emissions by large industrial emitters.



The transformation process and resulting business model will likely be unique to each utility, as each will craft a strategy that suits its specific market, energy sources, and regulatory/political environment. Canadian utilities are now engaged in this process, and some have begun to propose and implement strategic action plans as evidenced by the following examples.

ATCO Gas

ATCO has proposed several pilot projects designed to integrate renewable thermal energy delivery infrastructure into its utility service offerings. ATCO would design, install, own and operate geothermal space heating/cooling systems and solar hot water systems for new and existing residential and commercial buildings. The geothermal systems are designed to meet 100% of the heating and cooling requirements and the solar water heaters are designed to satisfy a portion of the hot water needs. Natural gas will supplement the hot water load and allow for other end-use applications (e.g., cooking).

ATCO believes that distributed geothermal and solar technologies are closest to market, but the current economics of these technologies are an impediment to market penetration. The pilots are designed to promote market penetration by making both the developer/building owner and homeowner/tenant indifferent between the cost of installing and operating a renewable system versus a conventional space heating/cooling and hot water system. For new construction, the developer pays the estimated cost of installing conventional space heating and water heating systems and ATCO funds the remaining cost of the renewable energy system. In existing buildings, ATCO installs and owns the system without contribution. ATCO then charges homeowners/tenants a fee equal to the difference between the cost to operate the renewable system and the estimated cost of operating a conventional system. ATCO estimates that at current energy prices the fee will not be sufficient to recover the revenue requirement of the incremental installation costs and it seeks regulatory approval to collect the incremental cost from all ratepayers.

ATCO cites the following objectives for its pilots:

- Gain practical experience with geothermal and solar technologies
- Evaluate technical functionality
- Gauge market acceptance
- Test business models
- Identify competitors and potential partners
- Introduce ATCO Gas name into the renewable energy marketplace
- Support renewable energy development and promote its consumption
- Cultivate renewable energy markets (develop industry participants, promote innovation and improve delivery)
- Test/validate GHG emission reductions

Terasen Inc.

Terasen Energy Services Inc. ("TES") is a Terasen company that specializes in developing alternative energy solutions ranging from renewable such as geoexchange, biomass and solar energy to waste heat recovery from sewer, industrial and commercial sources. TES finances, builds, owns and operates both geoexchange and district energy systems and it offers project management, design and construction services to others. TES offers its customers long-term contracts to ensure that their costs are competitive with traditional energy sources. Whether through TES or its regulated utility, Terasen Gas, Terasen is pursuing a variety of initiatives and projects in pursuit of this plan:

- Secured approval from the British Columbia Utilities Commission in 2009 for an expansion of its energy efficiency and conservation programs and to offer special tariffs for alternative energy solutions such as geoexchange, solar thermal and district energy
- Entered into Memoranda of Understanding and Letters of Intent with several school districts to evaluate, develop and implement alternative and renewable energy solutions
- Established agreements with the B.C. Bioenergy Network and Columbia Shuswap Regional District to explore a biogas project at the landfill site in Salmon Arm
- Entered into an agreement with Catalyst Power Inc. to advance the development of on-farm anaerobic digestion
- Invested in the on-site sustainable district energy system that provides space and water heating for Dockside Green, a mixed use community in Victoria. The district energy system is fueled by gas derived from biomass and supplemented by natural gas.
- Designed, owns and operates a geoexchange energy systems to heat and cool residences at a mixed use development in Victoria and a multifamily development in Kamloops
- Participated in a pilot program to provide LNG for a regional fleet of diesel trucks that transport waste material

In pursuit of this plan Terasen has developed alliances and partnerships with a variety of third parties, including other B.C. utilities, government and community organizations, and developers.

While devising unique business transformation strategies, each utility will likely confront a common strategic challenge. GHG policies and carbon pricing, in conjunction with new technologies and greater automation of grid operations, will expand market opportunities and attract new entrants targeting industrial customers, and commercial and residential loads of sufficient density to warrant their attention. New entrants realize that consumers don't demand traditional gas and electric utility service; they desire energy to heat and cool buildings and to power electrical devices or furnaces. Hence, utilities looking to transform their traditional business model to respond to competitive market threats face a critical initial strategic decision:

- Position the utility to compete in the integrated energy delivery services market on a regulated basis (e.g., special tariffs or broad ratepayer sharing of costs and benefits); or
- Create an unregulated affiliated company to compete for integrated energy delivery services (merchant integrated energy services provider); or a combination of the two.

This is a familiar challenge for utilities, and one they have faced in many jurisdictions as changes in government policy and technology advances carved new markets out of traditional utility services. Recent examples include competitive independent power generation (policy to disaggregate the traditional vertical utility to promote competition paired with advances in combined cycle gas turbine technology) and competitive energy commodity marketing and trading (policy to unbundle traditional utility services to promote competition paired with advanced telecommunication and computing technologies). In these cases, regulators had to decide whether to allow utilities to compete in these new markets on a regulated basis or allow utility participation only on an unregulated and arms-length merchant basis. This process has yielded a variety of business and regulatory models as utilities and regulators have crafted solutions that align with their assessment of local market conditions, competitors/risk of new entry, the importance of new services to traditional utility operations, and their vision on the role and goals of regulation. As this process plays out in the context of GHG policy it is likely to lead once again to a diverse array of business models. For example, Terasen appears to be pursuing new integrated and alternative energy services both on a regulated basis (e.g., Terasen Gas' new alternative energy service tariffs) and on an unregulated merchant basis (e.g., TES investments).

Several related strategic considerations come into play as utilities develop new business models:

- Regulation may significantly constrain business flexibility as regulators, ratepayers and competitors continuously scrutinize utility initiatives with concerns for cross subsidization, risk sharing, and preferential access to regulated assets.
- Large capital requirements to offer new services or enter new markets with greater investment risk could weaken utility credit ratings and may necessitate a need to deleverage utility balance sheets, and seek higher investment returns.
- Utilities will need to clarify the role of third parties in the new business model. Regulated utilities commonly contract with vendors to secure technology or specialized services (e.g., Smart Grid programs), but may need to expand on these practices with partnerships designed to share investment risk. Such partnership arrangements are likely best suited to the merchant model where both parties could invest directly in energy projects or assets without being subject to utility regulation. Moreover, a utility may prefer or need to partner with a potential competitor if that entity enjoys access to resources unavailable to the utility (e.g., proprietary technology).
- Some emerging new services may be critical to utility operations so that they need to be controlled by the utility and integrated into its traditional operations. Examples may be integration of electric vehicles and distributed small scale renewable electricity generation technology.
- Similarly, the integrated energy delivery services business model will require a widely distributed, highly reliable, and dynamic IT and communications infrastructure that will allow providers to optimize service delivery (e.g., integrate DSM with distributed renewable and CHP resources) while maintaining grid reliability. Incumbent utilities may want to control and operate this system.

As they address these and a host of other business transformation challenges, utilities understand that transformation can never be allowed to distract management from the core utility mission of maintaining high quality, low cost and reliable traditional electric and gas delivery services. Transformation into an integrated energy delivery model will take many years, and may take decades to reach traditional utility customers in non-urban areas or those areas lacking the stimulus of new development. Avoiding distraction risk, particularly in situations where developing and offering new services are not critical to core utility operations, may tip the balance in favor of segregating the pursuit of new services into a separate unregulated service company.

4. <u>What types of regulatory changes may be required to accommodate these shifts?</u>

Regulation is focused on ensuring that utilities provide universal and reliable service at the lowest reasonable cost, a goal that does not easily accommodate broader social objectives such as policies to reduce GHG emissions. Until GHG policies are adopted and establish a carbon tax or cost of carbon that can be evaluated alongside other utility costs, traditional regulatory practices and models present barriers to utility transformation. Overcoming these barriers require regulators to revise or suspend traditional regulatory practices through such means as socializing or cross-subsidizing the promotion of renewables and new technologies. So long as the cost of carbon is undefined, regulators must pursue GHG reduction goals indirectly through DSM, RPS and other such initiatives where the goal of reducing GHG emissions at minimum cost is made implicit rather than explicit. It was in this context that Dialogue participants considered the three models of regulator response to GHG policy risk: Activist, Efficient and Traditional.

Once GHG reduction goals are articulated and the form of GHG regulation is established, the cost of carbon will be quantifiable and can be explicitly accommodated in existing utility regulatory practices. Traditional regulatory mechanisms and practices are well suited to address quantifiable input costs. For example:

- Carbon costs can be readily incorporated in existing utility DSM cost effectiveness tests to validate utility investments and procurement decisions in response to GHG reduction goals. As was demonstrated in the Dialogue, the price of carbon is one of the key assumptions or "knobs" driving DSM cost effectiveness tests. A market-determined carbon price will greatly simplify decisions about where to set this knob.[6]
- Similarly, carbon costs can readily be incorporated into other traditional regulatory tools such as integrated resource planning, capital investment review and approvals, ratemaking, and cost recovery practices. Much as regulators developed fuel cost balancing accounts or "tracker" mechanisms a generation ago in response to oil market price volatility and natural gas price decontrol, these same mechanisms may be utilized to recover prudent utility costs of carbon compliance, which may well turn out to be similarly volatile and largely outside of a utility's control.

While traditional regulatory practices and structures are sufficiently flexible to accommodate utility business model transformation, a critically important element of successful transformation will be the coordination of business and regulatory strategy. Misalignment of strategic vision and/or misunderstanding on timing or purpose of investments between the utility and regulator can lead to inefficient capital deployment and cost recovery disputes. Avoiding significant transformation missteps requires starting a utility/regulator dialogue to arrive at a common vision of the appropriate utility business strategy, the timing to embark on business transformation, and the need for periodic reexaminations of evolving GHG policy and utility business models as appropriate. This conversation will focus on several key issues that regulators likely will seek to resolve in order to reach common strategic ground with utilities, including:

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[6] For example, in April 2009, the British Columbia Utilities Commission accepted Terasen Gas' proposal to include the BC carbon tax into its DSM cost effectiveness test [Order Number G-36-09].

- Which parties bear economic risk (e.g., investment risks, technology risks, product/market risks)?
  As part of their traditional mandate of ensuring just and reasonable rates, regulators will look to ensure that ratepayers do not bear inordinate economic risk associated with utility business model transformation. For example, as previously noted, in 2009 the British Columbia Utilities Commission approved new Terasen tariffs to allow cost recovery for alternative energy solutions such as geothermal heating/cooling and district heating projects. The costs and revenues associated with offering these services are allocated solely to the alternative energy service tariff rates to ensure that existing utility ratepayers do not bear the risk of these new services.

  Regulators will also look to entities capturing economic rents (i.e., new technology providers) or gaining access to new products and services (i.e., competitive energy service providers) to bear an appropriate share of risk. Risk sharing tools will be required, such as caps on investments or contracts between new technology providers and the utility specifying timely delivery, performance, and broad availability of new technology. For example, regulators will seek to ensure that smart meter vendors assume technology performance and timely availability risk in exchange for allowing utilities to recover smart meter program costs from their customers in rates.

- Which parties assume responsibility for energy service reliability?
  Because utilities have the ability to aggregate both energy supply and load through control of the grid, and because they are highly visible companies subject to regulation, they have long functioned as the supplier of last resort for residential and small commercial customers. Ultimately, regulators and the public-at-large are likely to look to utilities to ensure or backstop energy delivery service reliability at least for the small customer segment of the market. This may not be the case for large customers that have secured physical or commercial energy delivery service independent of the utility. As the energy delivery model evolves over time to a more distributed or community-based energy supply and delivery model, regulators may grow comfortable shifting reliability responsibility from the utility to the distributed or integrated energy service provider.

- What aspects of industry transformation are best left to unregulated competitive market solutions vs. regulated utility solutions?
  It would appear that certain aspects of the transformation may be best addressed through competitive markets:
  - New technology development and commercialization
  - New assets (e.g., combined heat and power, distributed generation) that can be developed, financed and contracted using traditional project finance structures
  - Development and marketing of integrated energy services

  However, regulators are likely to deliberate carefully before approving new utility business models and opening aspects of traditional utility services to competition because these industry structure decisions touch on critically important public policy issues:
  - Allowing competitive market participants to segment/cherry pick attractive loads while increasing stranded investment cost risk for non attractive loads

- Ensuring universal energy delivery service and access to energy delivery grids
- Maintaining energy delivery reliability/backstop of competitive service providers
- Access to and use of meter data
- Competitive advantage gained by utility access to lower cost rate-base financing
- Inclusion of low income and rural customers.

Ultimately, this regulatory review and approval process is likely to result in a mix of competitive and regulated services, much like the existing utility market. Regulators should welcome both innovation and competition where possible in both technology and service provider and exercise caution in not picking winners and losers. Regulators have long experience with these issues and have tools available to implement appropriate market and regulatory solutions. For example, stranded investment risk can be handled through traditional prudence reviews, accelerated depreciation accounting, exit fees, non-bypassable surcharges, and comparable mechanisms that spread infrastructure costs associated with transformation broadly to all market participants. Similarly, regulators may decide to transfer operations to an independent third party grid operator in order to open the grid to competitive service providers while also ensuring universal access and reliability. Regulators have already begun to address industry transformation issues (e.g., utility "Smart Grid" investments and commercial access to AMI meter data) and this process can be expected to accelerate as utilities respond to GHG policies.

While acknowledging the importance of these utility regulatory policy issues, the greatest barrier to industry transformation will likely be gaining public acceptance of the energy cost increases that inevitably will accompany targeted GHG emission cuts, at least in the near term. Energy delivery utility business model transformation will involve significant capital investments and accelerated replacement/redeployment of the existing capital stock. Current cost estimates are highly speculative, but some magnitude of the expense can be gleaned from industry sources. As cited earlier, ATCO plans to introduce a renewable energy delivery infrastructure into its utility service offerings. ATCO developed a framework for four pilot programs designed to introduce geothermal and solar technologies into its residential, commercial, and institutional markets. ATCO's estimated capital investment (after developer contribution) for these pilots ranged from $21,500 for a single residential geothermal/solar space heating and water heating system to $1,050,000 for a single commercial geothermal/solar building.

With costs of this magnitude, securing political support for utility transformation will be critical to its success. Failure of GHG policymakers to account for the cost of attaining GHG emission cuts poses serious financial and political risks for utilities and regulators as public opposition will rise with energy costs. To manage this risk, politicians and environmental policymakers designing GHG policies need to do so based on a full understanding of the cost implications of such policies for the energy delivery utility sector. In addition, during this process political leadership will be critical in informing the public of the utility cost implications associated with pursuit of GHG reduction policies and justifying the benefits of these initiatives. Today, as this GHG policy design process continues to unfold, regulators and utilities together share the responsibility to educate the policymakers on the utility business implications of implementing GHG policies and, most importantly, on a realistic estimate of the scale of investment required to transform the traditional utility model.