Transforming the Utility Business Model

Options to improve services and opportunities for clean energy in remote communities

Emily He, Grace Brown
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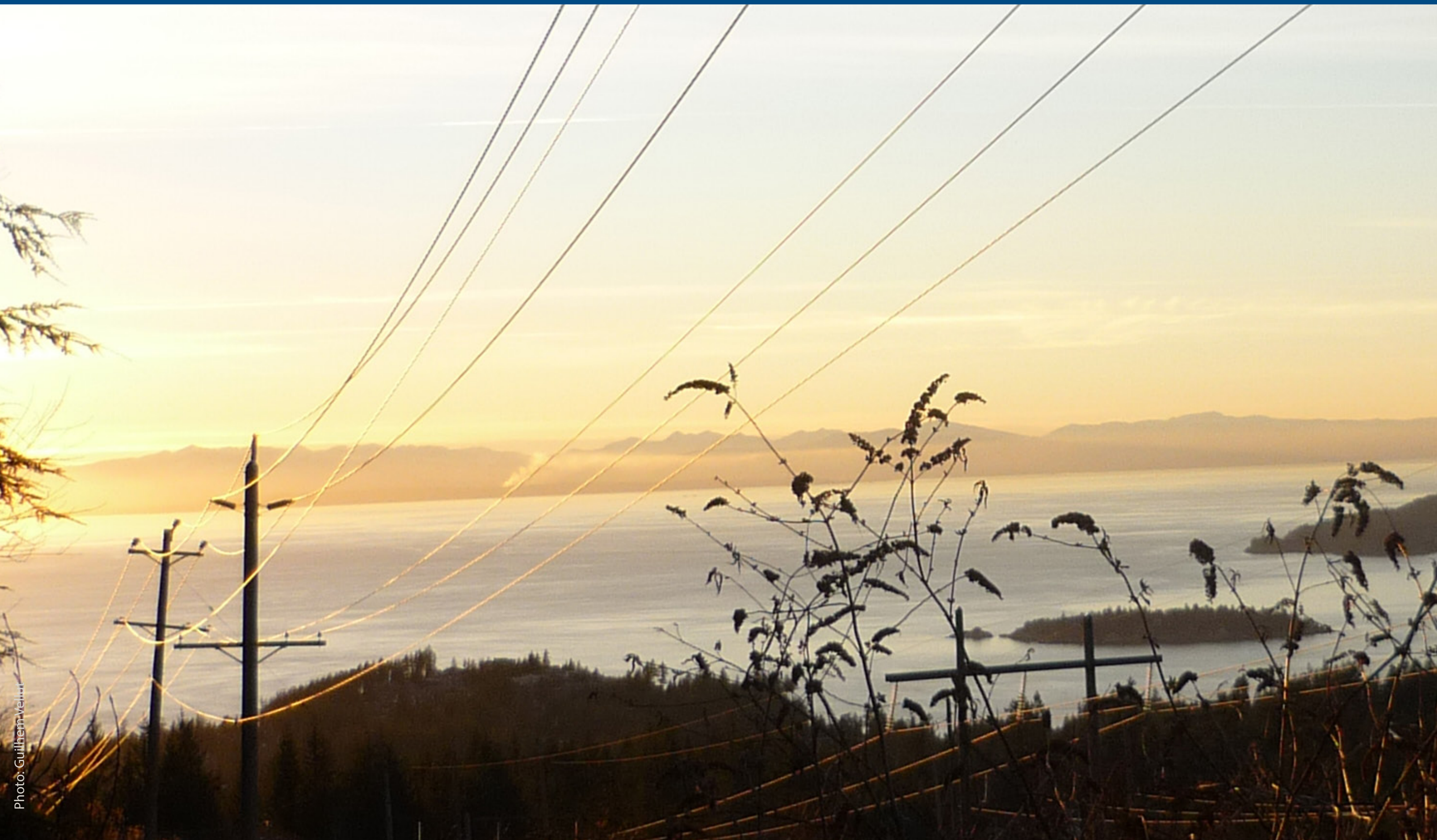
April 2022



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Cover photo: Guilhem Vellut, Flickr

Recommended citation: He, Emily, Grace Brown and Dave Lovekin. *Transforming the Utility Business Model: Options to improve services and opportunities for clean energy in remote communities*. The Pembina Institute, 2022.

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Acknowledgements

This work has been produced through support from the Indigenous Off-Diesel Initiative.

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Executive summary

Canada's national and international commitments to address climate change will require significant, sector-wide declines in greenhouse gas emissions. Climate action to drive down carbon will include the implementation of clean energy projects in remote communities which in turn need to rapidly accelerate. Moreover, the energy transition in remote communities, from diesel fuel to clean energy, must be inclusive. Indigenous businesses, entrepreneurs, and communities have been leading efforts to support energy-efficient housing and provide renewable energy in place of diesel, asserting their rights to self-determination and economic agency as well as taking on leadership roles in their community's clean energy transition.

Despite the growing number of renewable energy and energy efficiency projects in remote communities, projects are not being implemented at the speed and scale needed to meet provincial, territorial, and federal commitments to reduce the use of diesel power. A lack of opportunities for Indigenous proponents to implement clean energy projects, due to factors such as unfavourable and/or unavailable revenue streams, has slowed clean energy deployment as have barriers to project development including regulations that fail to support renewable energy coupled with pricing structures that favour diesel energy.

These barriers are embedded in the Cost-of-Service (CoS) business model that underpins how utilities operate. The CoS model financially rewards ownership of infrastructure and ties revenue to the amount of energy sold. This means that any non utility-owned renewable energy systems, as would be the case for Indigenous and/or community-owned projects, or reductions in energy demand due to an increase in energy efficiency projects, result in revenue losses for utilities. Consequently, utility business models need to be restructured so that revenue is not lost due to energy efficiency improvements and the introduction of clean sources of energy. Instead, utilities should be incentivized to support, and be active partners in, clean energy development.

Reforms to the utility business model can change the way utilities earn revenue and can modernize billing structures to better suit service offerings. Restructuring revenue generation will require endorsement and support from utilities, utility regulators, and different levels of government. Government must also initiate changes to policies that regulators are bound by. Policy revisions must be informed by climate action policies, energy innovation, greater customer engagement in the energy sector, and the prioritization of Indigenous-led projects recognizing the imperative of reconciliation and Indigenous rights while still ensuring that energy supply remains safe, reliable, and affordable.

The focus of this research is to identify the challenges that utilities face in servicing remote communities and to apply utility reform options that are now in effect in grid-tied jurisdictions to the remote community context.

Sixteen alternatives to the utility business model employed in remote communities were considered. Of those, four were identified as the best means of restructuring utilities servicing remote communities in support of policy priorities and Indigenous-led clean energy projects. The four options for utility reform are:

1. **Performance Incentive Mechanisms (PIMs)** – Through this option, regulators establish key performance indicators (KPIs) such as a KPI on the implementation of energy efficiency programs. If, for example energy efficiency uptake exceeds or, conversely, does not meet the pre-determined business-as-usual threshold, revenue to the utility will increase or decline accordingly. Utilities are thus incentivized to improve environmental performance, level of customer satisfaction, or other actions as determined by the regulator-defined metrics.

   Primary advantage: PIMs support alignment between utility operations and climate policy and can also support reconciliation goals if they are designed to reflect the community's priorities.

2. **Revenue Decoupling** – Under this option, units of energy sold do not determine the revenue realized by the utility. Instead, rates charged to customers fluctuate to reflect actual sales volumes. A ceiling on rate increases can be imposed to minimize increases. Additionally, the amount of revenue that a utility is required to generate can be adjusted to reflect actual spending or other market influences.

   Primary advantage: decoupling revenue from rates removes utility reluctance to support renewable energy and energy efficiency projects that would have reduced revenue under CoS, as a decline in energy sales no longer means lower revenues for utilities.

3. **Total Expenditure Approach (TOTEX)** – Through this option, utilities earn a return on capital and operating costs (currently, utilities only earn a return on capital costs), incentivizing utilities to choose the most economical option rather than prioritizing capital expenditures.

Primary advantage: after implementation of TOTEX, utilities can earn a return on Independent Power Producer (IPP) contracts, creating opportunities for Indigenous companies and communities to develop renewable energy projects.

4. **Platform Service Revenues** – This option allows utilities to serve as a "platform" operator for third-party energy service companies that can supply energy in addition to other energy-related services to customers, coordinating energy resources into the distribution system in exchange for fees that third parties pay the utility.

   Primary advantage: Platform Service Revenues benefit the utility, third parties, and customers – utilities secure a new revenue stream, barriers to market entry are lowered for third parties, and customers get a greater range of services to choose from.

Each of these reform options targets a different combination of objectives, as shown in the table below (more check marks mean better alignment with the reform objective).

Summary of utility reform options evaluated

		Utility reform option			
	Reform objective	PIMs	Revenue Decoupling	TOTEX	Platform Service Revenues
Reform Objective	Align utility operations with government climate policy objectives	✓✓✓	✓✓✓		✓✓
	Support distributed energy resource/energy efficiency implementation	✓✓✓	✓✓✓	✓✓	✓✓✓
	Remove utilities' incentive to grow energy sales so as to encourage energy efficiency projects	✓✓	✓✓✓		
	Support Indigenous reconciliation	✓✓✓		✓✓✓	✓✓✓
	Distribute risk and value sharing between utilities and third parties	✓✓	✓✓		✓✓

	Encourage cost containment			✓	
Pathway for Change	Change how rates are determined and/or structured		■		■
	New revenue opportunities	■		■	■

Determining which reform option(s) to adopt depends on the goals associated with the jurisdiction where a utility is located. Identifying those goals entails consideration of provincial and territorial climate and energy targets, in addition to regulator and utility mandates as dictated by provincial and territorial governments. Updating mandates should be a collaborative process between governments, regulators, and utilities to best reflect shared priorities.

Next steps: Working group on utility reform

Listed below are guidelines for a working group made up of government officials, regulators, representatives from utilities, and members of Indigenous communities to collaborate on opportunities for utility reform.

1. Identify and categorize new responsibilities for utilities to address climate change; reconciliation and Indigenous rights; and innovation and customer satisfaction.
2. Prioritize responsibilities and align with the intended outcomes of utility reform.
3. Identify the biggest challenges to adopting new responsibilities under the CoS model and existing regulations.
4. Identify and prioritize which of the following six utility reform objectives are most important for the jurisdiction:
    - Align utility operations with climate policy objectives
    - Support DER/energy efficiency implementation
    - Remove utilities' incentive to grow energy sales
    - Support Indigenous reconciliation
    - Distributed risk and value sharing
    - Cost containment
5. Identify which of the four options for reform best satisfy the selected objectives.
6. Revisit the main challenges in Step 3 to ensure that the selected reform options will address these challenges.
7. Map out what utility reform will look like in your jurisdiction. Determine which reform option to explore first. Study the impacts of reform on rates and revenues, conduct pilot projects, and evaluate how best to implement reform and whether it should be done in one or multiple stages. Identify the actions required from governments, regulators, and utilities to implement utility reform.
8. Coordinate next steps amongst working group members and stakeholders.

Recommendations

For governments

Eleven policy recommendations for provincial, territorial, and federal governments were identified to advance utility reform:

Provincial/territorial governments

1. **Expand the mandates of regulatory bodies overseeing utilities so that regulators can ensure that the way utilities operate is aligned with reform objectives such as climate change, reconciliation, and customer choice.** Regulators need to allow utilities to factor in costs associated with addressing reform objectives in rate applications. As such, regulator mandates should be extended beyond simply ensuring utilities are supplying the lowest cost of service. To avoid rate increases that may result if utilities implement new programs under the Cost-of-Service model, this will force both regulators and utilities to evaluate and implement utility reform.
2. **Create guidelines and new policy tools for regulators to follow and use to ensure that utilities incorporate federal, provincial, and territorial climate and energy plans into their operating practices.** Regulators will need more tools and increased support and guidance on how to undertake these new mandates.
3. **Prioritize Indigenous leadership in the clean energy transition through policy changes.** The United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) should be affirmed into provincial and territorial law and embedded in regulatory agencies. Utility and energy policies should be designed to prioritize Indigenous involvement in, and ownership of, projects to support the clean energy transition.
4. **Reform financial support systems for utilities.** Government funding should be targeted at supporting the economics of renewable energy and energy efficiency and should shift subsidies from diesel to lowering energy costs more broadly.
5. **Direct regulators to re-evaluate how utilities set consumer rates.** Utilities must be given agency to evaluate new and innovative methods of meeting their revenue requirements beyond charges for energy use on customer bills. For example, new charges could be included if the utility is acting as a Platform Service for a third-party provider.

6. **Implement Renewable Portfolio Standards (RPS) and increase funding and programming for renewable energy projects.** An RPS requires utilities to generate a percentage of their electricity from renewable sources. Under an RPS, a utility is required to purchase or generate renewable energy even if purchasing or generating diesel is cheaper. This will require utilities to re-evaluate their business models to adapt to these new costs and will reduce barriers for implementing certain reform options. Government support for implementation should come in the form of funding and programs that increase the penetration of renewable energy, allow utilities to create plans to meet standards, and increase opportunities for community engagement.
7. **Implement Energy Efficiency Resource Standards (EERS) and increase funding and programming for energy efficiency programs.** Establishing energy efficiency standards incentivizes utilities to offer programs that will reduce energy consumption by the end user. Current practice mitigates against this as less energy consumed means less revenue is generated for the utility. A new business model will be required so that selling less energy does not result in revenue losses. Like RPS policies, EERSs will require increased funding for energy efficiency projects.
8. **Increase funding to encourage utilities to explore different options to restructure their business practices.** Utilities and regulators need funding outside of their operating budget to test reform options in their jurisdictions.
9. **Establish a utility reform working group with representation from provincial/territorial and Indigenous governments, regulators, and utilities.**

Federal government actions

10. **Increase funding to spur innovation and support utilities to explore reform options.** Utilities and regulators need funding outside of their operating budget to test reform options in their jurisdictions.
11. **Establish a nation-wide government/utility collaborative process to support utility reform in remote communities.** The federal government can support reform by initiating the conversation in remote communities.

For regulators

Four recommendations on how regulators can support utility reform:

12. **Ensure early and active Indigenous participation in the regulatory process.** Regulators should hire Indigenous staff for decision-making roles and/or reform regulatory review processes to include local Indigenous governing authorities.
13. **Update rate structures and charges.** Regulations need to be revised and allow for more flexibility so that utilities have more agency over the rates charged to end users.
14. **Support the implementation of distributed energy resources (DERs) by updating renewable energy interconnection policies and increasing Independent Power Producer and net metering rates to accurately reflect the value of distributed energy resources.** To increase renewable energy penetration and increase opportunities for Platform Service Revenues, pricing structures and policies for ease of integration need to be adjusted so that financial and capacity barriers to project implementation are reduced or eliminated.
15. **Establish funding programs for pilot projects (often referred to as innovation sandboxes) to test the applicability of utility reform options for remote communities.**

For utilities

Three recommendations on how utilities can launch utility reform:

1. **Using the perspectives of both the utility and the customer, identify the objectives that reforms to the business model are intended to support. Based on those objectives, determine which reform options to implement.**
2. **Commit to Indigenous reconciliation and partnership.** Utilities will need to fully commit to reconciliation and forming strong, long-lasting partnerships with the communities they service.
3. **Assess the feasibility of new utility business models and propose these new business models to regulators.** Utility proposals are a concrete method to trigger the utility reform process by presenting the options to regulators and prompting a review.

Governments, regulators, and utilities must be proactive in evaluating and adapting their operations, and the regulations that govern them, to meet the evolving needs of customers and facilitate government commitments to decarbonizing the electricity grid. Working groups that include Indigenous community leaders should be formed to advance utility reform and jointly implement recommendations.

Altering the utility business model will allow communities to fully transition to clean energy. This way, utilities can enable rather than prevent project implementation. Whether the focus is climate and energy policy action, a decarbonized grid, equitable energy systems that prioritize Indigenous involvement and respects Indigenous rights, or customer demand for more services and a better experience, utility reform is a tool for these new responsibilities to be realized.

1. Introduction

1.1 Overview

Rapid decarbonization of the entire electricity sector is critical to achieving Canada's net-zero electricity sector emissions by 2035[1] and net-zero economy by 2050 goals. These targets place Canada in line with the International Energy Agency's 2035 net-zero electricity sector emissions deadline for advanced economies,[2] and contribute to avoiding global temperature rise above 1.5°C — the critical limit at which the world will experience the worst impacts of climate change.

Of the 182 remote communities in Canada, approximately 170 are Indigenous communities, representing a total population of over 100,000 people.[3] Remote communities, defined in this context as those without access to the North American electricity grid, are located across nearly every Canadian province and territory (except Prince Edward Island, New Brunswick, and Nova Scotia).[4] Currently, the majority of remote communities are serviced by regulated public and private utilities whose business models are not very conducive to advancing community- or Indigenous-led clean energy projects.

Despite this, these remote, predominantly Indigenous communities are rapidly and enthusiastically advancing renewable energy and energy efficiency projects: from 2015-2020, renewable energy projects nearly doubled across remote communities.[5] This progress is driven by many factors; most importantly in the context of this research, these are demand for increased environmental sustainability, local economic

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[1] Environment and Climate Change Canada, "Canada and the world move closer to powering past coal with more climate ambition at COP26," news release, November 4, 2021. https://www.canada.ca/en/environment-climate-change/news/2021/11/canada-and-the-world-movecloser-to-powering-past-coal-with-more-climate-ambition-at-cop26.html

[2] International Energy Agency, *Net Zero by 2050: A Roadmap for the Global Energy Sector* (2021), 20. https://iea.blob.core.windows.net/assets/0716bb9a-6138-4918-8023-cb24caa47794/NetZeroby2050-ARoadmapfortheGlobalEnergySector.pdf

[3] Dylan Heerema and Dave Lovekin, *Power Shift in Remote Indigenous Communities: A cross-Canada scan of diesel reduction and clean energy policies* (Pembina Institute, 2019). https://www.pembina.org/reports/power-shift-indigenous-communities.pdf

[4] *Power Shift in Remote Indigenous Communities.*

[5] Dave Lovekin et al, *Diesel Reduction Progress in Remote Communities* (Pembina Institute, 2020). https://www.pembina.org/pub/diesel-reduction-progress-remote-communities

development and energy sovereignty. Conversely, remote communities still face barriers to participating in the energy sector and increasing their energy sovereignty due to the limitations of existing policies, utility operations, and the regulatory environment utilities operate within.[6]

Utility business models, which dictate the means through which utilities earn revenue, are currently not designed to encourage the progressive and accelerated changes needed to advance the clean energy transition in Canada's remote communities. On the theme of this country's journey of reconciliation with Indigenous People, existing utility business models are not well aligned with creating opportunities for utilities to implement the Truth and Reconciliation Commission's Calls to Action or the United Nations Declaration on the Rights of Indigenous People (UNDRIP). Utility business model reform (hereafter referred to as "utility reform") encompasses actions at the utility, regulator, and government levels to change how utilities function and earn revenue through legislative and regulatory changes in order to alter the status quo business model that has been in place for decades. With national and global imperatives to increase efforts to reduce carbon emissions and mitigate the impacts of climate change, utilities across Canada, operating in both grid-tied and remote contexts, are experiencing pressure to change how they do business and decarbonize the energy systems they are currently responsible for. In the context of remote community energy policy and regulations, utility reform options must consider the unique challenges faced by utilities serving these jurisdictions. Through utility reform, utilities could play a critical role in supporting Indigenous-led clean energy projects as a lever for reconciliation rather than a roadblock.

This report provides an overview of the traditional electricity market and utility business model in the context of remote communities throughout Canada and highlights the limitations and risks of continuing with a business-as-usual approach. It reviews the unique challenges and emerging changes faced by utilities that serve remote and Indigenous communities and the relationships between governments, regulators, and utilities to identify opportunities for instituting utility reform. It examines in detail four alternatives to the traditional utility business model that can be applied in the remote community context and concludes with policy and regulatory recommendations to facilitate change. These changes must happen for remote, Indigenous communities to undergo, and be at the forefront of, a full and equitable energy transition.

[6] Dylan Heerema, "The future of the electric utility in Canada's remote communities," *Pembina Institute*, May 10, 2019. https://www.pembina.org/blog/remote-utility-future

1.2 Motivations for this research

Electricity systems around the world and in Canada are changing. When the dominant and current utility business model (the Cost-of-Service (CoS) model, described in Section 4.1) was established, rapidly constructing energy infrastructure to keep pace with and facilitate industrialization was the primary utility priority. However, as customer priorities evolve in the age of climate change and Indigenous reconciliation, solutions for these new priorities exceed the boundaries of the CoS model and what it was designed for.

Challenges to system resiliency arising from climate change, decarbonization, greenhouse gas (GHG) reduction needs, increased availability of energy efficiency solutions and distributed renewable energy, and customer desires for cleaner energy are causing utilities in grid-tied jurisdictions to change the way they do business. However, while remote and Indigenous communities are also, if not more so, experiencing the effects from climate change and equally wanting to see and participate in energy decarbonization, utility changes and responses to these pressures are happening much slower.

Some parallels can be drawn between grid-tied and remote-servicing utilities; however, utilities operating in remote and Indigenous communities face unique challenges and comparatively restrictive regulatory environments that can make changing policies and practices much more difficult. Changes in the energy landscape must be made to foster energy sovereignty and economic development for remote, Indigenous communities. Taking action to implement forward-thinking policies will allow utilities to proactively respond to this changing energy landscape.

1.3 Research goals, methodology, and scope

The overall goal of this research is to increase education and awareness for utility reform solutions that can be tailored to the remote community context and to set the stage for deeper collaboration with governments, utilities, and regulators on steps to explore utility reform solutions.

This research investigated the unique challenges faced by utilities serving remote communities in adopting proactive approaches that encourage the advancement of energy efficiency and renewable energy projects and respect Indigenous energy sovereignty and the principles of reconciliation. Solutions that have been applied in grid-tied communities were assessed for their appropriateness in addressing the specific challenges faced by remote communities.

The main objectives of this policy research are to:

- Assess the current state of the traditional Cost-of-Service utility business model and identify the limitations of this model within the changing energy landscape in remote communities.
- Summarize the main challenges faced by utilities servicing remote communities in adapting to new customer requirements and evolving energy and climate policies.
- Identify alternative utility reform options that have been used by grid-tied utilities and identify which ones may be suitable to the remote community context and why.
- Provide an overview of the various environmental, social, and utility rate impacts utility reform will have.
- Identify best practices for utility reform and evaluate options for utilities that operate in remote communities.
- Provide recommendations for policymakers, regulators, and utilities to begin exploring utility reform in remote community jurisdictions.

To accomplish this, we provide a review of utility, regulatory, and government bodies, structures, and relationships across relevant jurisdictions – examining Alberta, British Columbia, Manitoba, Newfoundland and Labrador, Ontario, Quebec, Saskatchewan, Northwest Territories, Nunavut, and Yukon. We also researched existing options for utility reform and evaluated jurisdictions in Canada and internationally that have already instituted utility business model changes, with a focus on reform options that are applicable to the remote community context.

The viability of each alternative reform option was qualitatively assessed to determine best practices for implementation and considerations within the remote context. Utility reform options explored in this report can be applied to both publicly and privately owned utilities. Larger utility and regulatory reform measures that require restructuring away from public or private utilities, such as creating utility cooperatives, were not assessed.

1.4 Definitions

The definitions listed here are used throughout the report.

Table 1. Definitions

Capital expenditures (CAPEX)	Costs for establishing and improving fixed physical assets like property, power plants, and equipment.
Capital cost recovery	Cumulative annual depreciation cost for a utility's rate base.
Contract-based wholesale market and regulated retail market	Market structure for public utilities in which the electricity market is not open to competition and rates are set based on long-term contracts regulated by the provincial / territorial regulator. Also commonly referred to as a regulated market.
Cost-of-Service	Traditional utility business model where revenues are set based on capital cost recovery, profit, and operating costs, with capital cost recovery being the only line item that utilities can change to impact their revenue requirement.
Depreciation	The annual amount of lost value for a utility's asset. If an asset was to be sold in any given year, the sell price is lower than what the utility paid for the asset. This decrease is equal to the cumulative depreciation.
Distributed Energy Resources (DERs)	"DERs are electricity-producing resources or controllable loads that are connected to a local distribution system or connected to a host facility within the local distribution system. DERs can include solar panels, combined heat and power plants, electricity storage, small natural gas-fuelled generators, electric vehicles and controllable loads."[7]

[7] Independent Electricity System Operator, "Distributed Energy Resources." https://www.ieso.ca/en/Learn/Ontario-Power-System/A-Smarter-Grid/Distributed-Energy-Resources

Energy Efficiency Resource Standard (EERS)	Specific, long-term energy savings targets for utilities. EERS policies state that utilities are required to procure a percentage of future energy needs (their projected load growth) via energy efficiency measures rather than new generation.
Energy security	The stable, reliable, and uninterrupted availability of energy sources that are accessible both in terms of price and interconnection.
Energy sovereignty	Inherent right of individuals, communities, and Indigenous peoples to make their own decisions regarding every aspect of the energy they use, from generation to distribution to consumption regarding sources, scales, ownership, and access structures.
General Rate Application	Application submitted by utilities to regulators for approval of their future rates based on forecasted operating and capital costs.
Grid-tied community	An area that is connected to the servicing utility's electrical grid and receives power from the utility's generation, transmission, and distribution systems.
Independent Power Producer	Renewable energy projects that are owned by renewable energy developers or companies other than the utility regulated to operate in the community. Electricity produced from these systems is sold directly to the utility. Electricity revenue is based on a formal contract between the provider and the utility.
Indigenous utility	"A 'public utility' for which, as the owner or operator, an Indigenous Nation has [...] control."[8] A utility with over 50% Indigenous ownership.

[8] British Columbia Utilities Commission, *Indigenous Utilities Regulation Inquiry Final Report Summary* (2020), 6. https://www.bcuc.com/Documents/Other/2020/DOC_57960_BCUC-Indigenous-Utilities-Inquiry-FinalReportSummary.pdf

Internal price on carbon	A tool used internally within companies, utilities or government that places a theoretical price on carbon emissions. This can help guide long-term decision-making processes in relation to climate change impacts and potential future carbon pricing policies.
Natural monopoly	Natural monopolies occur when a single company, rather than multiple competitors, can supply a product or service at the lowest cost. Natural monopolies are often regulated to ensure consumer protection.
Non-wire alternatives	Investments and utility programs that result in a reduction in the need for capital spending on infrastructure (generation or transmission) by the utility. This leads to a lower overall cost to supply energy.
Open wholesale market with retail competition	An electricity market where customers can either choose a regulated rate with long-term contract prices that have been set by agreements between generators and distributors or choose from a host of distribution companies offering competitive retail energy contracts based on the market price of electricity. Also commonly referred to as a deregulated market.
Operating expenses (OPEX)	Expenses incurred during business operations.
Private utility	For-profit companies governed by private boards and owned by investors or shareholders, who are generally not customers of the utility or members of the community. Also known as investor-owned utilities.
Public utility	Owned by the provincial or territorial government or a municipality that elects to provide its own electricity services for its residents. Also known as Crown utilities.
Rate base	Total monetary value for all assets a utility owns.

Regulated monopoly	Monopoly that is regulated to protect consumer interests.
Remote community	Communities without access to the North American electricity grid or natural gas infrastructure. Remote communities in Canada rely on local microgrids for electricity.
Renewable energy credit (REC)	Environmental attribute that tracks the renewable electricity generated from a renewable energy project, measured in MWh. Renewable energy projects can sell RECs to generate revenue.
Renewable Portfolio Standard (RPS)	Requirement that utilities generate a percentage of their electricity from renewable resources.
Return on equity (ROE)	A utility's net income divided by its shareholder's equity. ROE is a metric to evaluate a corporation's profitability and efficiency in generating profits. Higher ROE means higher income or lower shareholder equity.
Revenue requirement	The amount of money the utility needs to collect to cover their costs and potentially earn a profit. Established in a general rate application.
Self-determination	As defined in UNDRIP Article 3: "Indigenous peoples have the right of self-determination. By virtue of that right they freely determine their political status and freely pursue their economic, social and cultural development."[9]
Shareholder equity	Equal to a company's assets (i.e., a utility's rate base) minus its debt.
Total expenditures (TOTEX)	Total expenditures relating to a utility’s regulated business, equal to the sum of CAPEX and OPEX.

[9] United Nations, *United Nations Declaration on the Rights of Indigenous Peoples* (2018), 8. https://www.un.org/development/desa/indigenouspeoples/wp-content/uploads/sites/19/2018/11/UNDRIP_E_web.pdf

Third-party	A company that is not the utility.
Unbundled utility	In contrast to vertically integrated utilities, areas with unbundled electricity systems can be served by separate and/or multiple generation, transmission, and distribution utilities.
Utility regulator	Government body that regulates utility rates and operations to safeguard customer expenses while also allowing utilities to earn a reasonable profit. Also known as public utility boards or utility commissions.
Vertically integrated utility	A single company owns and operates all electricity equipment, including the generating facility, transmission system (if in a non-remote context), and distribution and retail services. Utility may be publicly or privately owned.

2. Challenges for utilities servicing remote communities

Some parallels can be drawn between grid-tied and remote community utilities; however, utilities serving remote communities face unique challenges and comparatively more restrictive regulatory environments that can hinder their ability to implement change in their energy systems. These challenges and regulatory restrictions pose unique barriers to Indigenous communities interested in developing their own clean energy projects as a path to achieving energy sovereignty.

The challenges experienced by utilities servicing remote communities must be understood to adapt solutions that overcome these barriers. These challenges differ from utilities that serve predominantly or wholly remote communities, acknowledging that some utilities serve both grid-tied and remote communities (e.g., BC Hydro) while others serve only remote communities (e.g., Qulliq Energy Corporation). Utilities serving remote communities face operational, contextual, and financial challenges to clean energy integration including:

- **Maintaining energy reliability / security** – Reliable electricity supply is a top priority in remote communities, resulting in higher operational cost and risk for utilities. Exploring renewable energy increases this risk for utilities.
- **Systems redundancy** – When renewable generation is added, diesel systems will have to remain as standby and dedicated backup to ensure power can be supplied in the event of an outage or maintenance. New business models will need to account for the costs associated with backup diesel systems until full technology migration away from diesel is possible.
- **High cost and limited access** – Isolated locations bring logistical challenges and high capital and operating costs for upgrades, repairs, and maintenance to energy systems.
- **High electricity rates** – High electricity rates (as a result of high costs, above) contribute to the high cost of living in remote communities. Utilities face pressure to keep rates low, hindering advancements that require large capital investments.[10]

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[10] Matt Vis, "Hydro One proposes rate hike for remote northern communities," *Elliot Lake Today*, November 30, 2017. https://www.elliotlaketoday.com/local-news/hydro-one-proposes-rate-hike-for-remote-northern-communities-779154

- **Dependency on diesel subsidies** – Utilities depend on ongoing diesel and energy subsidies to keep electricity prices somewhat affordable. This is elaborated upon in Section 2.1.
- **Small customer base and limited revenue** – If capital and operating costs increase, utilities have few options to grow revenue other than raising rates — but rate increases hit the small customer base of remote communities harder compared to a gird-tied utility where costs are more distributed.
- **Limited internal capacity** – Utilities serving remote communities have limited staffing and capacity to research, evaluate, and execute pilots of new business models, or to fully explore how to integrate renewable energy and energy efficiency into their operations.
- **Interconnection limitations** – Remoteness and vast distances between remote communities means it is typically not cost effective to interconnect these communities to larger grid networks. Community energy supplies therefore do not have access to wholesale markets where electricity suppliers offer competitive rates from varied energy sources.
- **Limited telecommunications infrastructure** – Opportunities to integrate smart grid technologies, such as smart meters that track how much electricity is used and when, are not feasible without upgrades to the telecommunication infrastructure in remote communities.

2.1 Subsidies supporting utility operation and electricity prices

Affordable electricity prices are important everywhere, but are particularly important in remote communities where energy rates are several times higher than the national average.[11] The high cost of living in remote communities means that any changes to electricity rates must be carefully planned and evaluated.[12] High utility operating costs, a small customer base, and limited funds for utility capital spending have created a dependency on government and ratepayer subsidies to provide lower rates. This dependency makes evaluating the implications of utility reform a financial, policy, and regulatory challenge. Furthermore, many utility reform options will require the

[11] Dave Lovekin, *Diesel Subsidies – Simplified, Part I* (Pembina Institute, 2021). https://www.pembina.org/pub/diesel-subsidies-simplified-part-i

[12] Jimmy Thomson, "How can Canada's North get off diesel?", *The Narwhal*, February 11, 2019. https://thenarwhal.ca/how-canadas-north-get-off-diesel/

continued, or even increased, subsidization of energy, at least in the short term, to support the capital costs of renewable energy integration with diesel energy systems during the energy transition.

Diesel subsidies mitigate excessively high cost of energy for individuals in remote communities, but also present a barrier to transitioning off diesel by artificially deflating the actual cost of producing and delivering energy since the majority of utilities do not publish or share the actual cost of electricity production. Therefore, the reliance on energy subsidies should be carefully evaluated in remote communities, especially if utility reform is to be considered and implemented.

3. Electricity market structures, policy, and regulations

3.1 Traditional electricity market structures

Electricity markets can be generally defined by three factors: 1) ownership structure, 2) market structure (or level of competition), and 3) level of integration between generation, transmission, and distribution systems. These factors and the interactions between them provide different avenues and opportunities to explore utility reform. These next sections discuss these three electricity market factors as they relate to utility reform. Because this section describes electricity markets in a broad sense to provide context on the system as a whole, not all information is applicable to remote communities. To compensate for the practical difficulties of delivering reliable electricity to physically remote communities without transmission interties to the provincial / territorial electric grid, market structures in these communities may differ from the rest of their province or territory.

3.1.1 Utility ownership structure

Utilities may be publicly owned, privately owned, or operated as a cooperative. Publicly owned utilities are owned by the provincial / territorial government, Indigenous government, or a municipal government. Public utilities generally do not earn a profit and exist to provide an essential energy service to the public. Private utilities are for-profit companies governed by private boards and owned by investors or shareholders, who are generally not customers of the utility or members of the community. Private utilities generally earn profits that are distributed to the shareholders.

In remote community jurisdictions, most utilities are publicly owned, including those operating in British Columbia, Saskatchewan, Manitoba, Quebec, Newfoundland and Labrador, Yukon, Northwest Territories, and Nunavut. Public utilities in Canada own or operate "equipment or facilities for the production, generation, storage, transmission, sale, delivery or provision of electricity, natural gas, steam or any other agent for the production of light, heat, cold or power to or for the public or a corporation for compensation."[13] While the provincial / territorial government owns the public utility that serves as the jurisdiction's primary electricity provider, independent power producers (IPPs) and municipal, cooperative, or private distribution companies may also supply electricity to certain regions within the province or territory.[14] These arrangements may exist due to historic precedent, have been implemented through government energy policy, or have been created to allow the utility to procure energy at a more advantageous cost.

3.1.2 Market structure (level of competition)

In traditional electricity markets, utilities operate as natural monopolies, with no competition for price or innovation. This structure comes with practical advantages. Having one service provider is the most economic way to deliver electricity to an area — one utility means that only one set of poles and wires needs to be financed and maintained. Duplicating this infrastructure would result in a considerable cost increase to customers.

However, monopolies in any industry can result in a misuse of power. For example, utilities could charge unfairly high electricity prices and customers would have no choice but to pay these high costs to the only electricity provider. Regulation is therefore needed to ensure electric rates remain reasonable for customers while providing an acceptable return on investment for the utility company. Utility regulators (often called public utility boards (PUBs) or utility commissions) serve to regulate utility rates and operations to safeguard customer expenses while also allowing utilities to earn a reasonable profit as defined under the regulation.

In provinces / territories with public utilities, the electricity market is not open to competition and is regulated by the provincial / territorial regulator. Thus, a customer's only choice is the regulated rate offered by the distributor in their area, with regulatory oversight provided by the regulator. The regulated retail rate offers a set, long-term

[13] British Columbia Utilities Commission, *Indigenous Utilities Regulation Inquiry Final Report Summary* (2020), 1. https://www.bcuc.com/Documents/Other/2020/DOC_57960_BCUC-Indigenous-Utilities-Inquiry-FinalReportSummary.pdf

[14] Pierre-Oliver Pineau, *Improving integration and coordination of provincially-managed electricity systems in Canada*, (Canadian Institute for Climate Choices, 2021), 6. https://climatechoices.ca/wp-content/uploads/2021/09/CICC-Improving-integration-and-coordination-of-provincially-managed-electricity-systems-in-Canada-by-Pierre-Olivier-Pineau-FINAL.pdf

price based on supply contracts between the province / territory's generators and distributors, or the vertically integrated utility.[15]

Alberta and Ontario: unbundled, open wholesale markets with retail competition

An alternative to the traditional electricity market is an open wholesale market with retail competition, as adopted in Alberta and, to a lesser extent, Ontario. In Alberta, electricity generators are paid for the power they produce based on the wholesale price of energy, which changes hourly.[16] This incentivizes lower prices for electricity customers, as electricity is purchased first from the least expensive generator. Although Ontario's market is structured the same as Alberta's, Ontario has reintroduced financial contracts that exclude many generators from the market price.[17] Provincially owned Ontario Power Generation provides over half of the power produced in Ontario.[18] Because of retail competition, customers in Alberta and Ontario can choose either a regulated retail rate (set under the same terms as in non-competitive markets) or a competitive retail energy contract. Competitive energy contracts are offered by a host of distribution companies, with rates based on the market price of electricity, rather than on long-term contract prices between generators and distributors.[19]

3.1.3 Integration between generation, transmission, and distribution

Contextualizing the distinctions between generation, transmission, and distribution is important because utility operations are heavily impacted by the level of integration of the services they provide.

Electricity moves from the production source to the point of consumption via three systems: generation, transmission, and distribution. Power plants generate electricity, which is transported through high-voltage transmission lines over long distances. Electricity then enters the distribution system through transformers, which lower the

[15] *Improving integration and coordination of provincially-managed electricity systems in Canada*, 9.

[16] Government of Alberta, "Electricity market review." https://www.alberta.ca/electricity-capacity-market.aspx

[17] *Improving integration and coordination of provincially-managed electricity systems in Canada*, 6.

[18] Ontario Power Generation, "Low-cost power." https://www.opg.com/strengthening-the-economy/low-cost-power

[19] *Improving integration and coordination of provincially-managed electricity systems in Canada*, 9.

voltage so the power can be used in homes and businesses. In remote communities, electricity reaches homes, community buildings, and businesses through local microgrids. Since microgrids locate the power generation source near the points of consumption, distribution lines can be connected directly to the power generation source with no need for high-voltage transmission.

In vertically integrated utilities, a single company owns and operates all electricity equipment, including the generating facility, transmission system (in a non-remote context), distribution system, and retail services. Although one company owns the entire electricity system, usually some level of market competition exists at the wholesale level, through allowing IPPs to generate and sell power or by allowing non-utility companies to sell power to the utility or provide retail services in their regions. An example of this market structure is in B.C. where although BC Hydro operates as a vertically integrated public utility, the utility acquires power from over 100 IPPs.[20]

In contrast to vertically integrated utilities, jurisdictions with unbundled electricity systems can be served by separate and/or multiple generation, transmission, and distribution utilities. In these areas, system operators are tasked with coordinating among the three sectors to deliver power smoothly to customers.[21] While this in theory presents increased opportunities for competition, in practice, most remote jurisdictions are still served by a single generation, transmission, and/or distribution utility.

Electricity markets across Canada vary broadly, from public to private utilities, non-competitive to open wholesale, and vertically integrated to unbundled.

Table 2 provides an overview of utilities that service remote communities and the province or territory's electricity market structure in which they operate. Most electricity markets in remote communities are public, non-competitive, and vertically integrated. The exemptions to these are the few private utilities (Yukon, Northwest Territories, and Newfoundland and Labrador) operating in remote communities. There is also some flexibility in retail options for remote servicing utilities in Alberta's unbundled deregulated market.

[20] BC Hydro, "Independent projects history & maps." https://www.bchydro.com/work-with-us/selling-clean-energy/meeting-energy-needs/how-power-is-acquired.html

[21] The Alberta Electric System Operator (AESO) oversees the safety, reliability, and economic operation of Alberta's competitive market and electric grid. The Independent Electricity System Operator (IESO) provides those services in Ontario.

Table 2. Remote community utilities within provincial and territorial electricity market structures

Province / Territory	Utility	Utility ownership structure	Level of competition	Level of integration
Alberta	ATCO Electric	Private	Open wholesale market with retail competition	Unbundled generation, transmission, distribution, and retail (grid-tied communities), vertically integrated (remote communities)
British Columbia	BC Hydro	Public	Contract-based wholesale market and regulated retail market	Vertically integrated
Manitoba	Manitoba Hydro	Public	Contract-based wholesale market and regulated retail market	Vertically integrated
Newfoundland and Labrador	Newfoundland and Labrador Hydro (NL Hydro)	Public	Contract-based wholesale market and regulated retail market	Generation and transmission separate from distribution (grid-tied communities), vertically integrated (remote communities)
	Newfoundland Power (NL Power)	Private		
Northwest Territories	Northwest Territories Power Corporation (NTPC)	Public	Contract-based wholesale market and regulated retail market	Generation and transmission separate from distribution (grid-tied communities), vertically integrated (remote communities)
	Northland Utilities (Yellowknife Limited and NWT Limited)	Private		
Nunavut	Qulliq Energy Corporation (QEC)	Public	Contract-based wholesale market and regulated retail market	Vertically integrated
Ontario	Hydro One Remote Communities	Private	Open wholesale market with retail competition	Unbundled generation, transmission, distribution, and retail (grid-tied communities), vertically integrated (remote communities)
Quebec	Hydro-Québec	Public	Contract-based wholesale market and regulated retail market	Vertically integrated

Saskatchewan	SaskPower	Public	Contract-based wholesale market and regulated retail market	Vertically integrated
Yukon	Yukon Energy Corporation (YEC)	Public	Contract-based wholesale market and regulated retail market	Generation and transmission separate from distribution (grid-tied communities), vertically integrated (remote communities)
	ATCO Electric Yukon	Private		

3.2 Government, regulator, and utility – relationships and responsibilities

Provincial / territorial governments play an important role in developing electricity policies, acts, and regulations and overseeing regulators based on these acts and regulations. Combined, electricity policies, acts, and regulations dictate the terms and conditions under which utilities operate.

As the need to establish climate plans and policies to decarbonize provincial and territorial energy systems grows in response to Canada-wide climate action, the responsibilities of provincial and territorial governments are expanding beyond simply defining electricity regulations and overseeing regulators. GHG accountability acts, clean energy acts, green energy and economy acts, and energy efficiency acts are becoming more common within jurisdictions that are proactive in addressing the climate crisis. These plans and acts cover different sectors of the economy. Some of these plans and acts developed by government have specific targets and goals for energy in remote communities, needed to meet the federal government's commitment of getting off diesel for electricity production in remote communities by 2030.[22]

Governments are also enacting acts and legislation around Indigenous rights and relationships, including reconciliation and Indigenous labour. The two examples of this include B.C.'s Declaration on the Rights on Indigenous People Act (DRIPA) and Nunavut's Inuit Labour Act.

To meet the goals and targets set through these various policies, governments must ensure that action is taken across the board — including determining how electricity

[22] Mélanie Ritchot, "Trudeau jets into Iqaluit to pledge $360M for housing if re-elected," *Nunatsiaq News*, August 30, 2021. https://nunatsiaq.com/stories/article/trudeau-jets-into-iqaluit-to-pledge-360m-for-housing-if-re-elected/

policy and regulation needs to evolve to account for new and growing priorities such as climate policy and Indigenous reconciliation. This is an emerging area where governments and regulators are grappling with their traditional mandates of electricity regulation and the direction things may need to take if electricity systems are to support climate goals. This evolving landscape of both electricity and climate policy is creating a disconnect when translating government policy into regulator mandates — sometimes among government agencies but also between government and the regulator. The result of this disconnect is that climate action is not currently effectively accounted for in utility regulation, and hence, operation.

Electric utility regulators issue regulations and rules to ensure that utilities provide safe, reliable, and affordable energy to their customers. They do this through reviewing utility GRAs and approving or denying utility proposals for the rates charged to customers and proposed infrastructure projects. Linking this to utility business models, regulators are responsible for creating the regulations that define the operating terms of the utility. Hence, regulators have the responsibility to ensure that any updates to utility business models are aligned with both utility and customer interests.

As listed in Appendix A, there are other responsibilities and language in acts and regulations that speak to “just, reasonable, fair, transparent and inclusive rates” as well as “promoting innovation in evolving electricity regulations.” This raises a question of how these responsibilities compare or rank in priority to the main regulatory responsibility and how these terms could drive regulators to incorporate climate action in their decision-making.

Utilities are responsible for providing safe, reliable electricity at a reasonable cost. Since many regulators hold and conduct public inquiries based on proposed rate changes from utilities, “reasonable cost” is often pushed to “lowest cost” in response to public preference for low rates. This poses challenges when making climate-conscious investments, as these will generally require higher costs — which can be met with customer resistance. This is especially valid in remote communities where the cost of living is already high. Electricity rates in remote communities are the highest across the country and utilities are driven by the regulatory review process that ensures rates are reasonable.[23]

Table 3 summarizes the responsibilities between governments, regulators, and utilities.

[23] *Diesel Subsidies — Simplified, Part I.*

Table 3. Government, regulator, and utility responsibilities

	Traditional	Emerging
Government	Develop electricity policies Write acts and regulations Oversee regulators based on acts and regulations	Set climate targets and policies to achieve these targets Direct specific actors (regulators and sometimes the utility through Special Directives) to achieve climate targets Align actions with Indigenous rights and relationships such as reconciliation and labour
Regulator	Provide market oversight and enforcement (in open market structures) Approve utility investments Ensure rates are reasonable Ensure safe, adequate, and secure services Approve long-term utility resource planning Establish an appropriate utility profit margin (balancing utility desires to earn a higher rate of return and customer interests to keep electricity prices low)	Ensure consumer protection Ensure utility long term planning reflects climate policy
Utility	Supply safe and reliable power at a reasonable cost	Some utilities (e.g., Toronto Hydro) are starting to develop their own climate action plans and targets

The relationship between various government, regulator, and utilities is shown in Figure 1. The specific relationships and roles between governments, regulators, and utilities vary across jurisdictions but interactions generally follow this pattern.

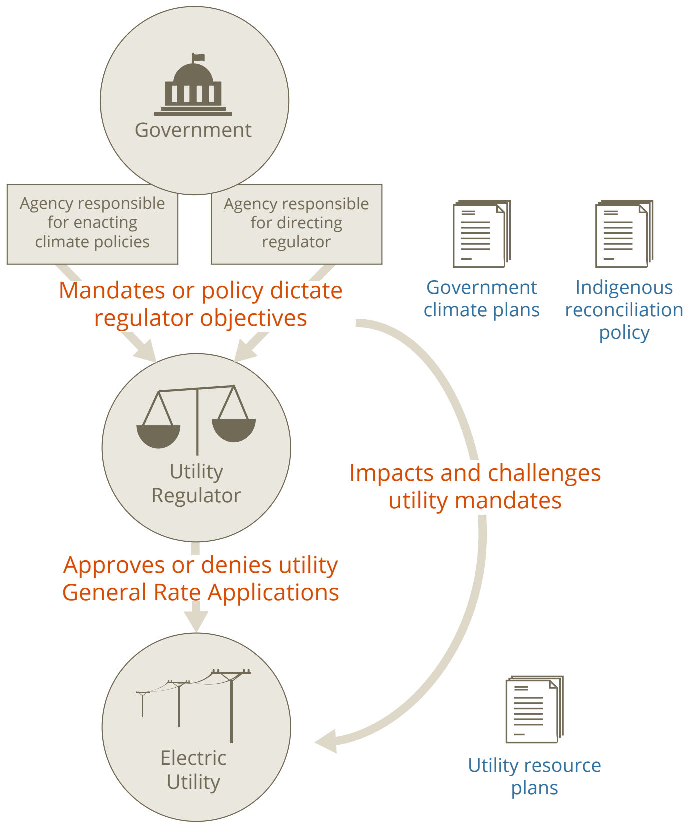


Figure 1. Government-regulator-utility influences

An example of the government-regulator-utility disconnect: British Columbia

This disconnect between climate plans, utility oversight, and utility actions is demonstrated in British Columbia, where the government's GHG reduction targets are not currently accounted for in the utility's long-term utility planning. BC Hydro's draft 2021 Integrated Resource Plan (IRP) determines the utility's electricity supply and demand strategy over a 20-year time horizon. The province's climate change legislation, the Clean Energy Act, includes the following in its energy objectives: "to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity" and "to reduce BC greenhouse gas emissions [...] by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007." These provincial energy objectives are reflected through the government's climate action plan — CleanBC. However, BC Hydro's current draft IRP's base case load planning is based on a scenario with limited electrification growth; it does not model the achievement of the outlined GHG reduction targets, contrary to what would occur if BC's climate plans were to be realized. The draft IRP does have contingency scenarios in which the GHG reduction targets are achieved; however, these are not the scenarios that IRP planning is based on.

Oversight and approval of BC Hydro's IRP is the responsibility of the BCUC, which, in turn, is directed by the Utility Commission Act (UCA), which states that "in determining [...] whether to accept a long-term resource plan, the commission must consider [...] the applicable of British Columbia's energy objectives [and] the extent to which the plan is consistent with the applicable requirements under [...] the Clean Energy Act." The UCA does indicate the necessity to account for climate targets in utility planning; however, there is a lack of clarity, prioritization and direction on how exactly these climate targets should be accounted for in utility planning. This lack of clarity has resulted in a misalignment between the government's CleanBC plan and electricity planning through the utilities IRP. The relationships shown in Figure 1 can be translated to illustrate B.C.'s government/regulator/utility relationship, seen in Figure 2.

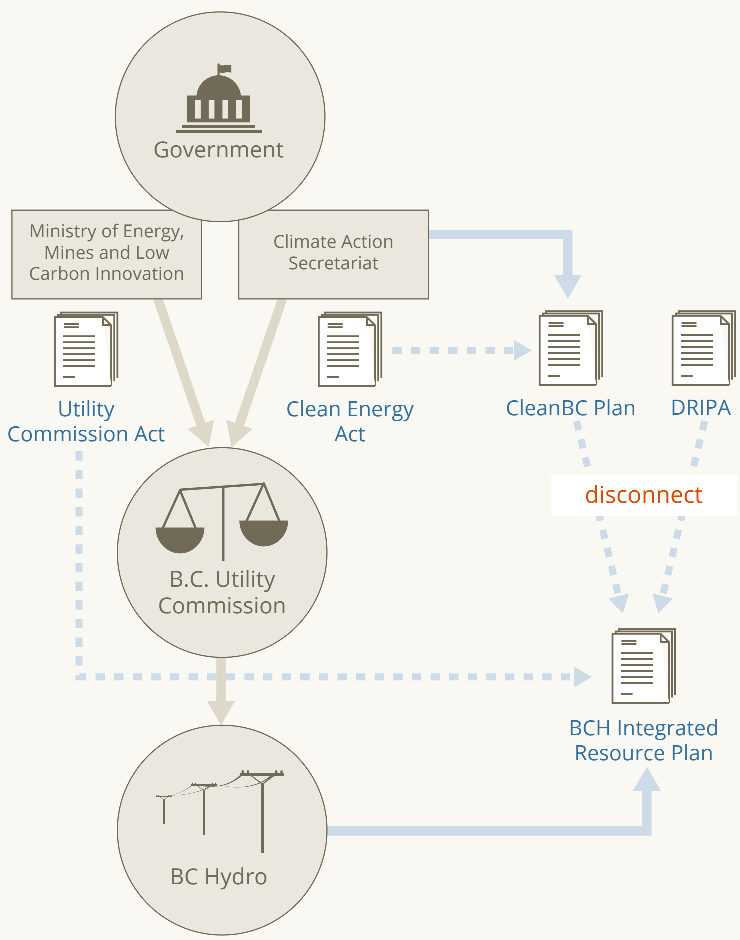


Figure 2. B.C.'s government-regulator-utility relationship

Utilities are not necessarily required to incorporate climate action into resource planning as current regulation in most instances still needs to be updated to reflect provincial and territorial climate policies. However, in some jurisdictions in Canada and the United States, utilities have taken action around climate change.

In order to meet the City of Toronto's net-zero goal,[24] Toronto Hydro developed a Climate Action Plan proposing projects for increasing transportation electrification, investing in building electrification and energy efficiency, procuring local renewable energy generation and storage, and modernizing outdoor lighting.[25] In the United States, Xcel Energy, a private utility that provides electricity and gas services to eight states, committed to delivering 100% carbon-free electricity and net-zero natural gas to its customers by 2050. Independent of regulator mandates or state decarbonization targets, the utility set its 2050 goal and interim targets to align with scenarios that limit global warming to 1.5°C as called for in the Paris Climate Agreement.[26] The leadership demonstrated by these utilities demonstrates the power that utilities have to lead on climate initiatives without specific parameters from government.

3.3 Legislation relevant to remote communities

Table 4 provides an overview of provincial and territorial electricity regulators and the key legislation under which they operate. Further details on the main regulator responsibilities and supporting climate policy are provided in Appendix A.

Table 4. Provincial and territorial electricity regulators and key governing legislation

Province / Territory	Regulator	Key governing legislation and purpose
Alberta	Alberta Utilities Commission	• Electricity Utilities Act (2003) – Primary electricity sector governing legislation • Hydro and Electric Energy Act (2000) – Ensures generation, transmission, and distribution are built economically, efficiently, and safely

[24] City of Toronto, "Net Zero by 2040: City Council adopts ambitious climate strategy," news release, December 15, 2021. https://www.toronto.ca/news/net-zero-by-2040-city-council-adopts-ambitious-climate-strategy/

[25] Toronto Hydro Corporation, *Climate Action Plan* (2021), 62-78. https://www.torontohydro.com/documents/20143/74105431/climate-action-plan.pdf/8fe4406c-7675-76a7-00c9-c0c4e58ae6df?t=1638298942821

[26] Xcel Energy, "Our Vision: Net-Zero Energy Provider by 2050," 2021, 3, 8. https://www.xcelenergy.com/staticfiles/xe-responsive/Clean-Energy-Transition-Highlights.pdf

		• Alberta Utilities Commission Act (2007) – Establishes the AUC
British Columbia	British Columbia Utilities Commission	• Utilities Commission Act (1996) – Primary electricity sector governing legislation • Hydro and Power Authority Act – Outlines the framework governing BC Hydro
Manitoba	Manitoba Public Utilities Board	• Manitoba Hydro Act – Establishes Manitoba Hydro powers • Crown Corporations Governance and Accountability Act – Requires Manitoba Hydro to submit rate changes to the PUB
Newfoundland and Labrador	Board of Commissioners of Public Utilities	• Public Utilities Act (1990) – Defines NL PUB responsibilities • Electrical Power Control Act (1994) – Gives NL PUB regulatory oversight over NL Hydro, including setting rates • Hydro Corporation Act (2007) – Further defines NL Hydro roles and responsibilities
Northwest Territories	Public Utilities Board	• Public Utilities Act – Establishes NT PUB and provides authority to approve rates
Nunavut	Utility Rates Review Council	• Utility Rates Review Council Act – establishes URRC as advisory body for QEC • Qulliq Energy Corporation Act – Establishes QEC as sole generator and distributor of electricity in Nunavut
Ontario	Ontario Energy Board	• Electricity Act (1998) – Outlines the framework for the competitive electricity marketplace • Ontario Energy Board Act (1998) – Outlines the OEB mandate
Quebec	Régie de l'énergie	• The Act respecting the Régie de l'énergie – Outlines the framework for Québec's regulated and competitive electricity marketplaces • Hydro-Québec Act – Outlines Hydro-Québec roles and responsibilities, establishes that IPP generators can fulfill utility generation requirements where necessary
Saskatchewan	Saskatchewan Rate Review Panel	• Crown Corporations Act (1993) – Establishes the Crown Investments Corporation as managing entity for SaskPower • Power Corporation Act – Grants SaskPower exclusive rights to supply, transmit, and distribute electricity in the province
Yukon	Yukon Utilities Board	• Public Utilities Act (2002) – Provides the regulatory framework under which the YUB regulates public utilities • Yukon Development Corporation Act (2002) – Establishes the Yukon Development Corporation,

		parent company of YEC, Yukon's main electricity generator and transmitter

Regulators are governed by acts that grant oversight powers to the regulator and establish responsibilities of utilities. As seen in the above table, acts and their purpose differ within each province and territory. Looking more closely at regulations in each jurisdiction (summarized in Appendix A), regulators in the majority of provinces and territories operate under narrow mandates that require them to focus on regulating utilities based on system reliability and to ensure that customer electricity rates are reasonable. Because of these narrow regulator mandates, regulators do not have the authority to introduce regulations outside of their defined roles, nor the ability to authorize utilities to modify their business models to meet modern challenges related to decarbonization and climate goals (such as increased building and transportation electrification, changing load structures, and increased customer demand for renewable energy).

An example of a current and amended narrow regulatory definition is the QEC Act, which states that QEC is the only entity who "may engage in the retail supply of power in Nunavut" and that "the objects of [QEC] are to generate, transform, transmit, distribute, deliver, sell and supply energy on a safe, economic, efficient and reliable basis." The second clause has since been amended to include "purchase" after "deliver", such that QEC remains the sole entity for the retail supply of power. However, other entities can sell their power to QEC (but still cannot sell their power to other consumers).

Narrow regulator mandates may also hinder provincial and territorial decarbonization goals. With the exception of Alberta and Nunavut, all of Canada's provinces and territories have active climate action plans that call for electricity sector emissions reductions but it is unclear and vague as to whether these emission reductions extend to remote community jurisdictions.[27] However, because the primary mandate for regulators is to ensure system reliability at a reasonable cost to consumers, implementing measures to meet provincial decarbonization targets are currently not part of or required in utility planning processes.

Some jurisdictions show that mandates can be updated to take these challenges into consideration. For example, regulator mandates in Ontario have expanded to include

[27] Nichole Dusyk and Isabelle Turcotte, *All Hands on Deck: An assessment of provincial, territorial and federal readiness to deliver a safe climate* (Pembina Institute, 2021), 17-40. https://www.pembina.org/reports/all-hands-on-deck.pdf

consumer protection.[28] In British Columbia, the Clean Energy Act includes a provision "to facilitate the participation of First Nations and Aboriginal people in the clean energy sector."[29] Under the Greenhouse Gas Reduction (Clean Energy) Regulation, utilities are able to recover the cost of a range of GHG mitigation measures through increasing their revenue requirement in GRA applications.[30] These expanded mandates allow regulators more options for influencing utility policies to focus on a broader range of issues in addition to the typical considerations of cost and reliability.

[28] Government of Ontario, *Strengthening Consumer Protection and Electricity System Oversight Act*, S.O. 2015, c. 29 - Bill 112. https://www.ontario.ca/laws/statute/s15029

[29] Government of British Columbia, *Clean Energy Act*, [SBC 2010], Chapter 22, Part 6. https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/10022_01

[30] Government of British Columbia, *Greenhouse Gas Reduction (Clean Energy) Regulation.* https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/102_2012

4. The traditional utility business model

What is a utility business model?

A utility's business model defines the utility's approach to delivering value to their customers and how they generate revenue and profit from delivering that value. This approach is shaped by the three main electricity market factors discussed in Section 3.1: the utility's ownership structure (private, public, or member-owned), the level of competition in which the utility operates, and the level of integration within that market (vertical integration versus unbundled generation, transmission, distribution, and retail). Public policy mandates, regulations and regulatory processes, technological changes, and customer needs also influence the utility's business model. As these factors change in response to current market trends and customer demands, a utility's financial incentives may become increasingly misaligned with its former business model, creating a need for reform.[31]

4.1 The Cost-of-Service model

Utilities use the "Cost-of-Service" (CoS) model to determine their revenue requirement and corresponding customer rates. The CoS model is the most common business model employed by utilities across North America as well as by utilities servicing remote communities.

4.1.1 Utility rates and revenue requirements

Utilities submit applications to regulators for approval of their future rates (a General Rate Application (GRA)) based on their planned operating and capital costs. Through public inquiries and reviews, interveners including expert witnesses and utility customers can comment on these rate applications. The revenue requirement defines

[31] Dan Cross-Call, Rachel Gold, Cara Goldenberg, Leia Guccione, and Michael O'Boyle, *Navigating Utility Business Model Reform: A Practical Guide to Regulatory Design* (Rocky Mountain Institute, 2018), 7. https://rmi.org/insight/navigating-utility-business-model-reform/

the amount of money the utility needs to collect to cover their operating costs and potentially earn a profit.

The revenue requirement is comprised of three components: operating costs, capital cost recovery, and profit:

- Operating costs include expenses for operations and maintenance, interest on debt, and insurance.
- Capital cost recovery accounts for the depreciation of physical infrastructure, also known as capital assets. Essentially, if an asset were to be sold or retired in any given year, the price at which it would be sold would be lower than what was initially paid for the asset by the utility due to depreciation. Thus, utilities need to recover this lost value in the form of the "capital cost recovery" portion of their revenue requirement. It is important to note that the more expensive an asset, the greater its depreciation will be, as depreciation is a function of asset value. Utilities calculate depreciation on a straight-line basis, i.e., depreciation is a constant amount annually. Capital cost recovery is calculated for all assets a utility owns, and the total value of all assets in a utility's portfolio is termed the "rate base".
- Lastly, utilities can (but do not always, as in the case of publicly owned utilities) earn a profit. The regulator is responsible for establishing an appropriate profit margin that balances both utility desires to earn a higher rate of return and customer interests to keep electricity prices low.

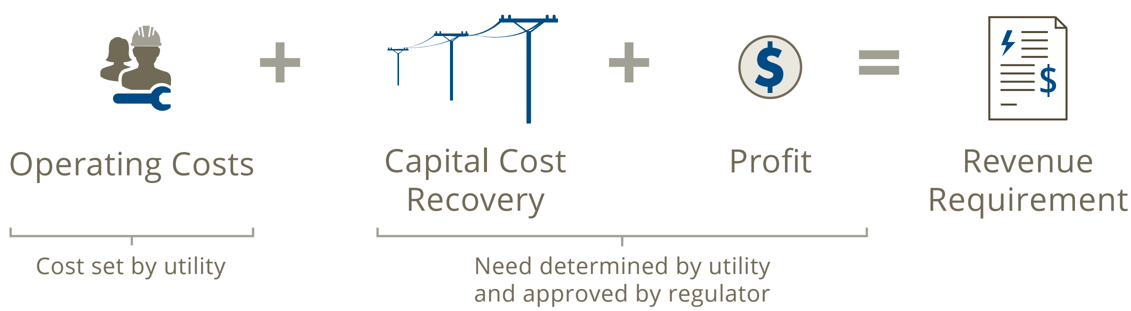


Figure 3. Components of the revenue requirement

Given this revenue requirement, electricity rates are set such that the various customer groups (generally some division of residential, commercial, institutional, and government customers) each pay a fair portion of this revenue requirement. Electricity rates are set based on the predicted energy demand from customers in different billing classes such that utilities can recover their revenue requirement, as shown by the three equations in Figure 4. Hence, electricity rates do not dictate utility revenues, the revenue requirement does.

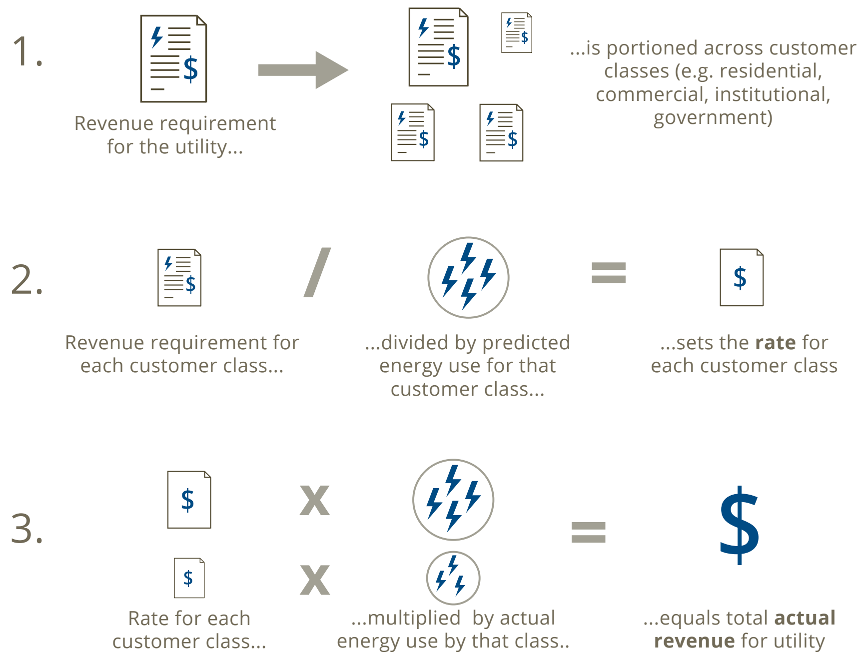


Figure 4. Rate setting under the traditional utility business model — linking revenue requirement, rates, and actual revenue

4.1.2 Utility revenue and the Cost-of-Service model

Under the CoS model, illustrated in Figure 5, utilities cannot earn a profit on operating costs and hence can only increase their revenues through owning more assets, which increases their capital cost recovery and allows them to earn a return on these capital assets.

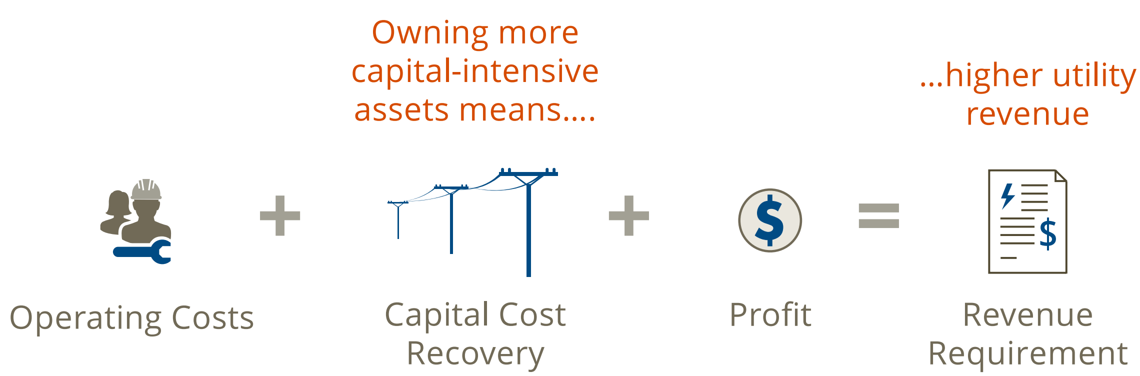


Figure 5. The Cost-of-Service model

Some jurisdictions across North America have undergone minor to major utility reform, adjusting the baseline CoS model to reflect a "CoS-plus" model, to be discussed in Section 6.7. However, this change has not been adopted by utilities servicing remote communities. Examples of utility reform in other jurisdictions are also described in Section 6.7. Hypothetical CoS-plus impacts on utility revenues are shown in Figure 18.

4.1.3 Limitations of the Cost-of-Service model

Under the CoS model, utilities are motivated to protect their revenue by selling consistent or increasing amounts of electricity in addition to maintaining a capital-intensive rate base. The model actually makes it difficult for utilities to purchase renewable energy, retire diesel generation, or enforce measures to reduce energy demand:

- If renewable energy is purchased from Independent Power Producers (IPPs), utilities can not add the renewable energy infrastructure to the rate base.
- Early retirement of diesel infrastructure assets also reduces the rate base.
- Energy efficiency measures decrease electricity demand, and hence revenue.

In remote communities, where this rate base is predominantly comprised of diesel infrastructure, this method of deriving profits is clearly misaligned with provincial, territorial, and federal climate policy, diesel reduction, and decarbonization goals; it also does not account for, nor incent, prominent Indigenous participation and ownership in the energy sector.

With renewable energy projects and energy efficiency initiatives increasing throughout remote communities, utilities servicing these communities will start to, if they do not already, feel the pressures of customer desires for increased distributed energy resources (DERs) and improved environmental performance.[32] Indigenous communities are actively pushing for energy sovereignty and are developing low-carbon energy and housing solutions in their communities.[33] However, under the CoS model, these progressive projects result in lost revenues for utilities, shaking the foundation of their operations. Utilities must explore alternative options for revenue generation so they can proactively respond to these changes while remaining profitable and continuing to deliver reliable electricity service.

[32] Dave Lovekin et al, *Diesel Reduction Progress in Remote Communities* (Pembina Institute, 2020). https://www.pembina.org/pub/diesel-reduction-progress-remote-communities

[33] Rochelle Baker, "Indigenous-led clean energy projects can fuel reconciliation," *Canada's National Observer*, November 4, 2021. https://www.nationalobserver.com/2021/11/04/news/indigenous-led-clean-energy-projects-can-fuel-reconciliation

Summary of limitations of the Cost of Service Model

- Disincentive to reduce sales (discourages DERs)
- Incentive for capital investments over operational changes
- Varied information availability between stakeholders
- Judicial ratemaking process limits innovation
- Limits on utility revenue and profit opportunities
- Limits Indigenous participation and independence

4.1.3.1 The utility death spiral

Demand reduction from energy efficiency and renewable energy can relieve grid congestion and brownouts in remote micro-grids — deferring the need for costly infrastructure upgrades, and lowering GHG emissions.[34] However, it also results in lower revenue from decreased electricity sales. For utilities, collecting lower revenue than the amount defined in the revenue requirement means that customer energy rates would need to increase to meet said revenue requirement. However, increased rates will further incent customers to pursue energy efficiency or renewable energy to avoid these higher costs. This feedback loop of demand reductions and corresponding rate increases is termed the "utility death spiral," shown in Figure 6.

[34] United States Environmental Protection Agency, "Local Energy Efficiency Benefits and Opportunities." https://www.epa.gov/statelocalenergy/local-energy-efficiency-benefits-and-opportunities

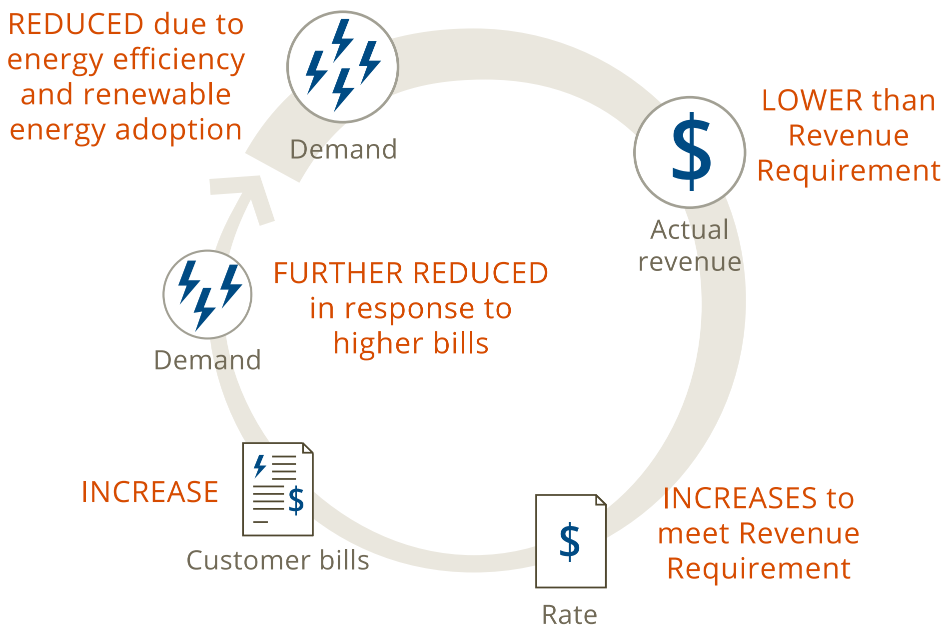


Figure 6. The "utility death spiral"

Utility death spiral impacts in other jurisdictions

In 2018, 71% of utilities in the United States saw the death spiral as a "real, potential outcome if utilities fail to implement their own alternative energy solutions, or if regulatory models preclude market flexibility."[35] In other words, regulations must be updated to allow utilities to adapt to meet market (and policy) needs. Potentially because utilities have proactively responded to the threat of the utility death spiral, tangible impacts have not been widely observed in United States utility markets.[36]

In the early and mid-2010s in Germany, electric utilities reported annual revenue losses in the range of several billion dollars due to the nation's energy transition. These revenue losses were attributed to utilities decommissioning fossil fuel power plants as electricity demand decreased, which in turn lowered wholesale electricity prices. In response, utilities became more proactive in entering the renewable energy market and seeking new revenue streams to limit unforeseen impacts. These measures have had positive impacts, with utility stocks increasing since the initial shortfalls due to the death spiral. EnBW, a German utility that implemented utility reform efforts prior to seeing the effects

[35] Paul Shepard, "71% of U.S. Utilities see the "Utility Death Spiral" as a Possible Future Scenario," *EE Power*, August 22, 2018. https://eepower.com/news/71-of-u-s-utilities-see-the-utility-death-spiral-as-a-possible-future-scenario/

[36] Herman Trabish, "The other death spiral utilities are beginning to deal with," *Utility Dive*, August 6, 2015. https://www.utilitydive.com/news/the-other-death-spiral-utilities-are-beginning-to-deal-with/403286/

of the death spiral, was able to mitigate some energy transition impacts — in 2015 they saw a 13% drop in their stock price compared to a 25% and 54% drop for their less-proactive competitors, E.ON and RWE.[37]

The effects of the death spiral could very well occur in remote communities if utility reform action is not taken. For example, in the Northwest Territories, NTPC is already experiencing net revenue losses over 1% as a result of customer-owned renewable energy. This would require rate increases of 1.3% by 2030.[38]

In contrast to the infrastructure needs of years past, the current energy landscape is being driven more and more by climate and energy policy, the imperative to decarbonize electricity systems, increasing customer demands for clean energy projects, and the need for advancement of Indigenous energy sovereignty. Utilities must explore alternative options for revenue generation so they can proactively respond to these changes while remaining profitable and continuing to deliver reliable electricity services.

[37] Eric Hopf, Will O'Brien, Timothy Downs, Alistair Pim, *Mitigating an Energy Utility Death Spiral in the United States: Applying Lessons from Germany* (International Development, Community and Environment (IDCE), 2017), 12.
https://commons.clarku.edu/cgi/viewcontent.cgi?article=1165&context=idce_masters_papers

[38] Intergroup, *Net Metering and Community Self-Generation Policy Review* (2021), 20.
https://www.inf.gov.nt.ca/sites/inf/files/resources/gnwt_net_metering_and_community_generation_review.pdf

5. Evolution of utility business models

5.1 The need for reform

Utility responsibilities

Utility mandates are bound by acts and the regulations that operationalize the details of legislation. Historically, utility mandates have focused on supplying reliable, safe, and affordable electricity. While mandates for utilities have remained unchanged for decades, climate policy has rapidly evolved over recent years and continues to evolve, as does energy innovation, increased customer inclusion, and the prioritization of Indigenous-led projects through the lens of reconciliation and Indigenous rights.[39] Utilities are no longer expected to simply supply energy that is safe, reliable, and affordable, but are increasingly being asked to respond to a new set of principles and responsibilities, as shown in Figure 7. These principles are grouped into three categories: 1) climate change; 2) reconciliation and Indigenous rights; and 3) innovation and customer satisfaction.

[39] Autumn Proudlove, Brian Lips and David Sarkisian, *The 50 States of Grid Modernization: 2020 Review and Q4 2020 Quarterly Report* (NC Clean Energy Technology Centre, 2021). https://nccleantech.ncsu.edu/wp-content/uploads/2021/02/Q42020-GridMod-Exec-Final.pdf

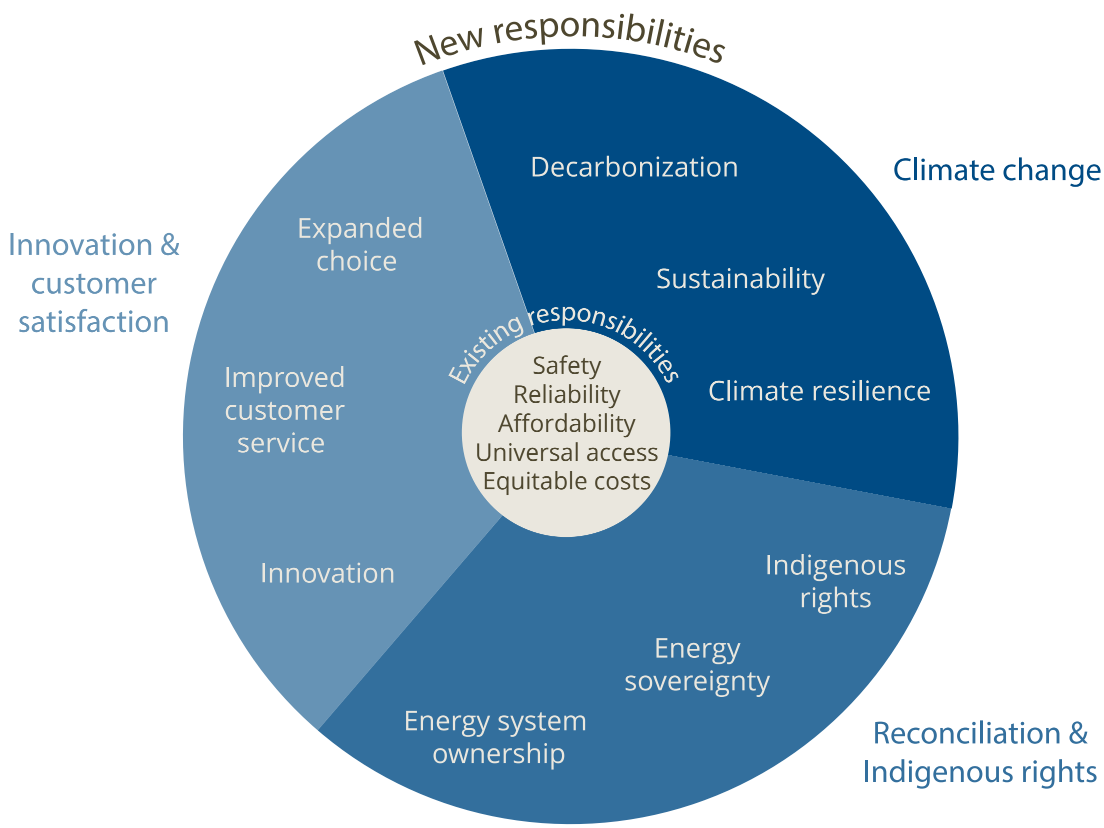


Figure 7. Existing and new utility responsibilities

In the context of Indigenous communities and their right to self-determination, energy sovereignty, and economic development, ownership over energy infrastructure and operational control is of particular importance. With an increasing number of communities implementing renewable energy projects, actively participating in the energy sector, and expressing enhanced interest, utilities are experiencing increased demand to ensure an inclusive energy sector that provides opportunities for participation by non-utility and, especially, Indigenous proponents.[40]

The reasons why utilities that operate in remote communities do not currently respond to these pressures is complex and correlated to many of the challenges highlighted in Section 2. However, at the root of the problem are the restrictions placed on utilities as shown in Table 3, that fail to address climate change, reconciliation and Indigenous rights, and innovation and customer satisfaction as utility responsibilities. Utility

[40] Terri Lynn Morrison, "Surging Indigenous renewable projects lead shift to clean energy future," *Corporate Knights*, April 20, 2021. https://www.corporateknights.com/energy/indigenous-communities-leading-clean-energy-future/

reform is a crucial and necessary process which can alleviate many of these restrictions and enable Indigenous communities to effectively lead and participate in a more equitable and sustainable energy future.

New ways to meet responsibilities

In addition to a growing list of utility responsibilities, approaches to meeting these responsibilities are also emerging. For example, historically, customer needs or growing electricity demands were met by upgrades to power plants, transmission lines, or distribution systems. However, capital upgrades are no longer the only, most economic, equitable, or most efficient way of addressing system improvements. Alternative responses include distributed energy resources (DER) where customer-owned generation meets load demand, avoiding utility investments; software solutions (including cloud computing services, energy-monitoring software, and data analytics) for utility data collection to make more informed investment decisions, and infrastructure such as load management equipment and smart meters to better manage peak loads. These kinds of options may be most efficiently provided through an external company rather than the utility itself. However, as stated previously, under the CoS model, expenses for external services and non-utility owned infrastructure are not profit generating. Consequently, utilities are not incentivized to consider the most cost-effective solutions.

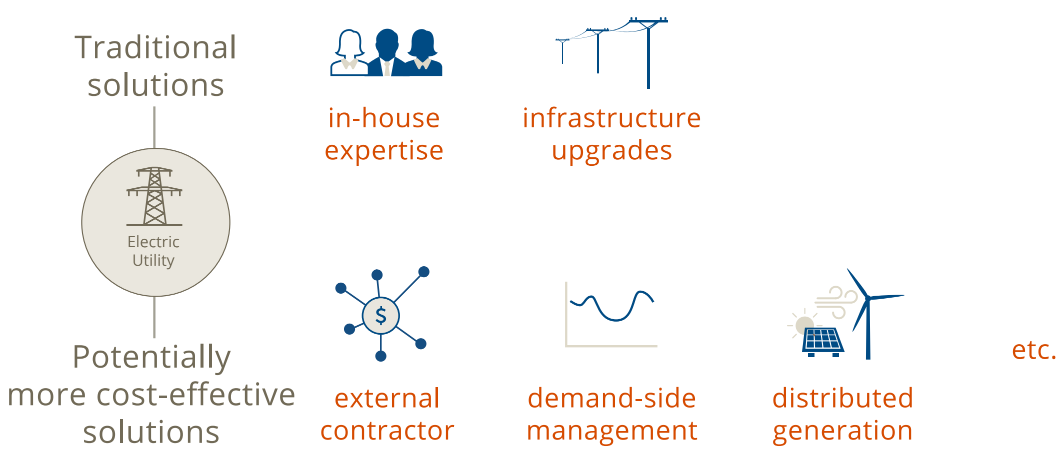


Figure 8. Traditional vs emerging solutions for utilities

The Government of Yukon has already re-evaluated certain aspects of expense inclusion in a utility's rate base. In 2019, the government issued two Order-in-Councils, which required the regulatory body to approve costs associated with purchasing power from third parties. This order from government ensures that utilities could recover the costs associated with supporting the IPP policy. Without the Order-in-Council, Yukon utilities would still be restricted under the CoS model and third parties would still have limited opportunities for implementing clean energy projects.

5.2 Reform objectives

Utility reform can address the limitations of the Cost-of-Service model (Section 4.1.3) and fulfill new factors that utilities must take into account:

- Climate change
  - Decarbonization
  - Sustainability
  - Climate resilience
- Reconciliation and Indigenous rights
  - Rights to self-determination
  - Energy sovereignty
  - Energy system ownership
- Innovation & customer satisfaction
  - More options for customers
  - Improved customer service
  - Innovations in clean energy

Objectives for utility reform are listed in Table 5. Alternatives to the traditional CoS model can be assessed against these objectives, depending on jurisdictional priorities and policy and customer goals.

Table 5. Utility business model reform objectives

Objective	Description	Emerging utility responsibility addressed
Align utility operations with climate policy objectives	Improvements to utility environmental performance should result in financial benefits assuming the utility is tracking to policy targets.	Climate change
Support DER/energy efficiency implementation	Accelerating the transition to clean energy is one of the primary objectives of utility reform	Innovation and customer satisfaction Climate change

Remove utilities' incentive to grow energy sales	Utility revenue needs to be decoupled from energy sales to increase utility support for energy efficiency and renewables.	Innovation and customer satisfaction Climate change
Support Indigenous reconciliation	Utilities can recognize Indigenous utilities and IPPs as legal actors that can supply energy to Indigenous communities. This will also help advance reconciliation and energy sovereignty.	Reconciliation and Indigenous rights
Revise risk and value sharing	Business and investment risks should be equitably shared between utilities, third parties, and customers rather than one party bearing adoption risks that may be associated with renewable energy or energy efficiency.	Innovation and customer satisfaction
Encourage cost containment	Efficient operations control costs and minimize spending.	Innovation and customer satisfaction

Based on RMI[41]

Some of these utility reform objectives are more important than others in the context of the clean energy transition in remote communities. The utility reform options evaluated in the following subsections were selected based on their potential to achieve one or more of these six utility reform objectives and their applicability to remote communities.

5.3 Reform options assessed

While many options exist for instituting utility reform in grid-tied communities, this research focuses only on utility reform options applicable to remote communities. Of the 16 utility reform approaches researched, four models are explored in detail: **Performance Incentive Mechanisms (PIMs), Revenue Decoupling, Total Expenditure Approach (TOTEX),** and **Platform Service Revenues**. This research also reviewed several other utility reform options; however, they were identified as not feasible or applicable to the remote utility context. These include Benchmarked Revenue Requirements, Cost Trackers, Earnings Sharing Mechanisms / Shared Savings Mechanisms, Future Test Years, Lost Revenue Adjustment Mechanisms, Minimum Bills, Multi-Year Rate Plans, Price Cap, Rate Case Moratorium, Revenue Cap, Straight Fixed-Variable Rates, Time-Based Rates.

[41] *Navigating Utility Business Model Reform*, 29.

Research and analysis of utility business models is rapidly progressing – new utility reform options and alternative means of applying existing utility reform options continue to surface. Utilities servicing remote communities are more sensitive to change than grid-tied jurisdictions, for reasons outlined in Section 2.

6. Alternatives to the traditional utility business model

6.1 Introduction

Utilities can implement reforms that allow them to respond to their new and emerging responsibilities through two primary pathways for change: **rate design reform** (changing how electricity rates are designed and how customers are charged) or **new revenue opportunities** (establishing new avenues to collect revenue). These pathways for change should not dictate what utilities ultimately select for implementation, as reform options should be selected based on the objectives at hand, but they are useful to get a sense of the end impacts of each reform option and can guide implementation.

Table 6 summarizes how each of the four utility reform options performs to satisfy the six reform objectives defined in Table 5 (more check marks mean better alignment with the reform objective), and whether that is accomplished through rate design or revenue changes.

Table 6. Summary of utility reform options evaluated

		Utility reform option			
	Reform objective	PIMs	Revenue Decoupling	TOTEX	Platform Service Revenues
Reform Objective	Align utility operations with government climate policy objectives	✓✓✓	✓✓✓		✓✓
	Support distributed energy resource/energy efficiency implementation	✓✓✓	✓✓✓	✓✓	✓✓✓
	Remove utilities' incentive to grow energy sales so as to encourage energy efficiency projects	✓✓	✓✓✓		
	Support Indigenous reconciliation	✓✓✓		✓✓✓	✓✓✓

	Distribute risk and value sharing between utilities and third parties	✓✓	✓✓		✓✓
	Encourage cost containment			✓	
Pathway for Change	Change how rates are determined and/or structured		■		■
	New revenue opportunities	■		■	■

6.1.1 About performance-based regulation

Performance-based regulation encompasses many utility reform options that aim at aligning utility performance and incentives with environmental, customer, and community value. These methods can be applied individually or in tandem with one another. Figure 9 illustrates how performance-based regulation impacts utility revenues on a high level. The exact way in which performance impacts revenues differs between reform options. Figure 9 shows the cornerstone of all performance-based regulation reform options: performance, in one way or another, has a direct impact on utility revenue. This can be contrasted with the traditional CoS model in Figure 5.

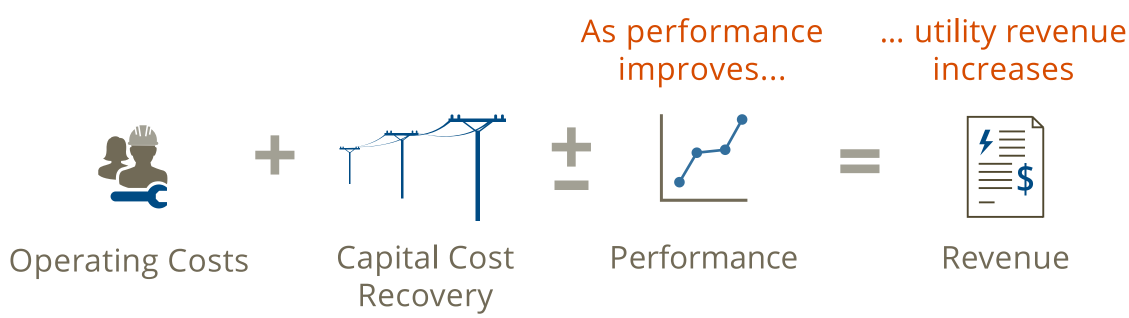


Figure 9. Revenue impacts of performance-based regulation

The two forms of performance-based regulation discussed in this report are Performance Incentive Mechanisms and Revenue Decoupling, which were determined to be the most relevant utility reform models in the remote context. Other types of performance-based regulation that were identified as not ideal or applicable in the context of remote communities are not reviewed. For example, multi-year rate plans set revenue requirements over multiple years for one general rate application to contain costs both in terms of utility expenditures and regulatory needs as compared to annual rate plans. Multi-year rate plans are already in place in many remote-serving utilities such as the Northwest Territories Power Corporation and are aimed at only encouraging cost containment rather than meeting multiple reform objectives at once as the selected reform options do.[42] Furthermore, multi-year rate plans do not require the same level of discussion as other reform options in this report as they can be relatively easily implemented under current operations. Hence, multi-year rate plans are not described in detail below.

6.2 Alternative business model option 1 — Performance Incentive Mechanisms

Performance Incentive Mechanisms (PIMs) are trackable metrics tied to performance targets, resulting in financial incentives or penalties for utilities. PIMs can be established by policymakers and regulators with input from utilities and third parties to identify areas utilities should target to align with utility reform objectives. PIMs incentivize utilities to invest in programs which they previously did not have a financial incentive to promote (for example, energy efficiency, if the performance target is linked to the uptake of energy efficiency projects or demand reduction).

There are two primary methods for rewarding utility performance: **return on equity (ROE) increases** or **direct incentives**. ROE is used to measure a company's financial performance and is determined by dividing profits by shareholder equity (the value of a utility's assets, minus the utility's total debt) and are approved by regulators. So, if PIMs are tied to performance such that regulators allow ROE increases, profits also increase. PIM incentives can be tied to increasing the ROE, and hence profits, by fractions of a percent if objectives are met. Conversely, ROE could decrease if targets are not met, although this is not feasible for not-for-profit utilities as they do not earn any return that could be decreased. Direct incentives, on the other hand, do not affect a utility's allowed profit and are awarded on top of the predetermined revenue requirement.

An ROE increase would mean an increase in customer rates, whereas direct payments may stem from government payments for achieving policy objectives. As such, direct payments would likely have lower impacts on ratepayers.

[42] Northwest Territories Power Corporation, "Rate Regulation." https://www.ntpc.com/about-ntpc/rate-regulation

Examples of PIMs include, but are not limited to, reduction of peak loads, reduction of CO_2 per MWh, emissions reductions for baseline output, grid reliability, and customer satisfaction regarding their energy services and utility interactions. All PIMs need to be clearly quantifiable and measurable; measurement of progress is generally done by benchmarking a utility's historical performance or benchmarking against other utility performance. Tracking and reporting PIMs can increase information availability and provide insight otherwise lacking from utilities to regulators and other stakeholders.

One PIM that is harder to quantify is a mechanism to increase energy efficiency. Measuring and verifying the effectiveness of energy efficiency progress can be done in a variety of ways. Energy efficiency PIMs are often attributed to total program spending towards energy efficiency measures. However, this fails to motivate utilities to pursue the most efficient or effective programs to achieve the greatest energy savings. This can be mitigated by instead, or in tandem, linking energy efficiency PIMs to demand reductions or other specific goals. This intricacy illustrates the impacts PIM design can have toward actually achieving utility reform goals. An example of utility rewards for energy efficiency PIM incentive calculation is shown in Figure 10.

Figure 10. Energy efficiency PIM calculation example

6.2.1 PIMs — utility reform best practices

Designing reward mechanisms and thresholds is crucial to success. Rewards should only be given for outstanding performance; business-as-usual improvements should not be rewarded. This requires significant benchmarking and agreement between regulator and utility entities as to what qualifies as business-as-usual. PIMs are especially sensitive to seemingly minute details in reward mechanisms — if targets fail to properly capture the intended effects of PIMs, arbitrary swings in compensation may result. Moreover, poor PIM design can, in the worst case, lead to adverse and unintended incentives that do not correlate with the impacts of utility actions. Unintended consequences should be mitigated by implementing targeted case studies where effects can be better evaluated for each jurisdiction.

When designing PIMs, regulators may be inclined to set incentives low to limit these unintended consequences. However, PIM incentives should be set sufficiently high such that utilities and potentially shareholders are motivated to take immediate action. Compensation should be adequate to address what would otherwise be shortfalls in meeting a utility's revenue requirement that would have resulted from PIM investments. Regulators should take heed to neither over- nor under-compensate utilities in comparison to the magnitude of the achieved benefits.

PIMs, set by regulators, should be informed by provincial, territorial, and federal energy and climate policy goals and ratepayer interests. PIMs are most effective to target objectives with clear and achievable outcomes. If metrics are overly complex, measurement and verification of success becomes increasingly uncertain and mechanisms may be less effective in achieving desired results. Care should also be taken when setting baselines to track progress against; uncertainties may result in controversies and disagreements between the utility and regulator when evaluating results.

It is also important to consider how individual PIMs affect one another. Multiple PIMs with individual price signals targeting the same metric may introduce additional confusion for utilities at how to best achieve PIM goals. This can also introduce problems of "double counting" if utilities are rewarded twice for one action.

Regulators should ensure that the right balance is achieved regarding the portion of utility revenues coming from achieving objectives and how much is coming from customer electricity bill payments. Determining this balance depends on the proportion of any decreases in actual revenue compared to the revenue requirement that the regulator or utility sees fit that PIMs address.

PIMs are most effective when utilities operate with multi-year rate plans to allow utilities to reinvest PIM revenues towards meeting reform objectives before revenues are "balanced out" in a general rate application. Regulators should consider lengthening the time between rate applications to allow PIMs to fully achieve intended effects. The timeframe in which PIMs are rewarded is also significant; regulators must distinguish if PIMs should be evaluated on an annual basis (requiring a higher regulatory burden but providing utilities with immediate direction on the impacts of their initiatives) or periodically, allowing utilities sufficient time to implement actions to target PIMs.

Overall, successful PIM implementation requires support for utility reform across government, regulator, and utility stakeholders, as shown in Figure 11.

Government	• Define policy objectives • Mandate regulators to implement performance objectives • Supply subsidies to incentivize utilities and mitigate potential price impacts to ratepayers
Utility Regulator	• Establish performance metrics to align with legislation and customer priorities • Design PIM structure • Verify utility achievements • Benchmark utility performance • Evaluate rate setting timeframe
Electric Utility	• Benchmark utility performance • Establish and implement action plans to meet PIM goals • Measure PIM outcomes • Receive incentives and/or penalties

Figure 11. Government, regulator, and utility roles in PIM implementation

6.2.2 PIMs — the remote context

While PIMs can be seen as a possible route for effective utility reform, their implementation also requires a fair amount of support. Establishing PIM thresholds, benchmarking, measurement, and verification will require sufficient capacity on both the utility and regulator fronts — this may be a limitation for already capacity constricted remote servicing entities. Regarding reward mechanisms in the remote community context, government payments through direct incentives would be preferred over adjustments to utility ROE to mitigate impacts to ratepayers. As such, implementing PIMs will require support from the relevant agencies to subsidize utility rewards. For public utilities serving remote communities that generally operate as not-for-profit entities, penalties for failing to meet objectives may be harder to implement. Penalties are usually delivered as a reduction in the utility's allowable profit margin. Because not-for-profit utilities do not operate as for-profit entities, alternative, non-monetary penalties must be considered.

The level of effort required for implementing PIMs is extensive; however, PIMs can serve as an effective means of addressing several objectives for utility reform. In remote communities, PIMs could be used to promote utility collaboration with Indigenous peoples and companies. Specific metrics could be tied to programs targeted to Indigenous proponents and procurement methods which prioritize Indigenous bidders.

6.3 Alternative business model option 2 — Revenue Decoupling

A key issue the CoS model fails to address is the reduction of utility revenues due to an uptake of energy efficiency and customer-owner renewable generation, which results in utilities limiting adoption of customer clean energy projects. Revenue Decoupling aims to segregate revenue from the units of energy sold to address this concern. In the CoS model, rates are set by looking at the utility's rate base and estimating how each class of customers is going to contribute to recovering revenue, as shown in Figure 4. In Revenue Decoupling, rates reflect actual sales levels to keep revenues consistent with expectations. By removing the influence of sales volumes to revenues, Revenue Decoupling removes utility incentives for high customer energy consumption.

As with the CoS model, Revenue Decoupling starts with establishing a utility's revenue requirement and base electricity rates using the existing methodology. However, once rates are implemented, rates can be adjusted on a periodic basis (ranging in frequency from a per-billing cycle basis to annually, depending on decoupling design) to collect necessary utility revenues, as shown in Figure 12. To mitigate undue rate increases and burden on consumers, rate changes are generally capped to a set percentage in a given adjustment period. General Rate Applications are still required periodically to allow regulators and stakeholders to fully assess how rates are tied with utility spending and customer demand.

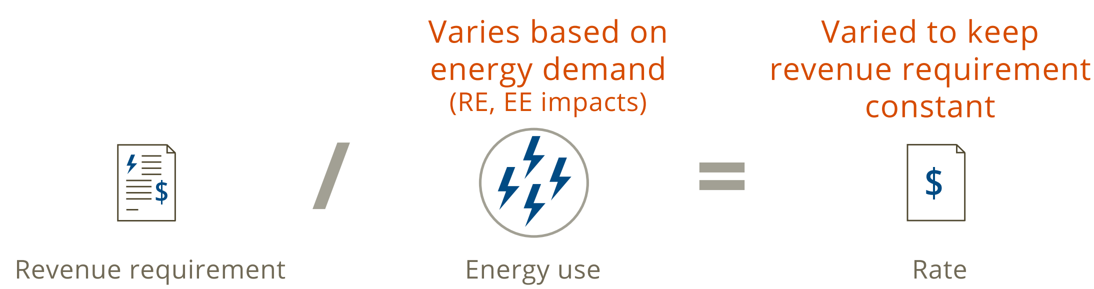


Figure 12. Revenue Decoupling formula

Revenue Decoupling can be implemented in part or in full, depending on the objectives for utility reform, as shown in Table 7.

Table 7. Degree of Revenue Decoupling

Degree of Revenue Decoupling	Description
Full	All deviations from expected revenues result in an adjustment to rates, within an allowable range.
Partial	Only some revenues are impacted by sales: a shortfall revenue would only result in rate changes within an allowable range and tied to specific metrics, such that a specified percentage of revenue was recovered. For example, the percentage could be tied to energy targets. If the target was met, utilities could recover 100% of their losses; however, if the utility fell short, only some losses could be recovered.
Limited	Rate adjustments, within an allowable range, are only triggered by specific mechanisms. For example, if implemented in tandem with a utility-operated energy efficiency program, Revenue Decoupling could trigger rate adjustments based on an established amount of lost revenue from said program.

Beyond rate adjustments, Revenue Decoupling can also account for misalignments with utility actual spending and revenue requirement between rate cases by adjusting the Revenue Requirement, although this is not always done. If revenue adjustments are made, they can be implemented by the following methods:

- **Stair-step**. Revenue adjustments are defined in General Rate Applications based on forecasts of future costs.
- **Indexing**. Minor adjustments are based on various factors such as inflation, productivity, customer growth, and changes in capital. Indexing allows for some flexibility without a new rate application.
- **Customer base**. Revenue is established by regulators on a per-customer basis. This allows revenues to be adjusted to reflect the number of customers.
- **Periodic review**. Revenues are reviewed annually to adjust for incremental and decremental quantifiable changes in operating and capital costs. Like indexing, periodic reviews allow for some flexibility without a new rate application.
- **Assumption factor**. A predetermined and regulator approved factor, aka a “K factor,” for adjusting revenues between rate cases to better match growth in costs. K factors can be applied if it is predicted that some significant change will occur between rate cases, for example a large uptake in energy efficiency or solar PV.
- **Hybrid**. Any combination of the above mechanisms.

6.3.1 Revenue Decoupling — utility reform best practices

As with any utility reform mechanism, implementation and design is paramount to success. Revenue Decoupling insulates utility revenues from demand uncertainties due to energy efficiency and renewables in addition to making utilities less risk adverse when exploring rate designs which encourage peak load reduction and energy efficiency such as time of use rates, which utilities may have previously been hesitant to adopt to avoid unintended consequences.

However, Revenue Decoupling itself does not incentivize utilities to invest in or promote energy efficiency or customer-owned generation. As such, Revenue Decoupling should be implemented in tandem with energy efficiency PIMs and/or programs such as energy efficiency resource standards (EERS) that require specific, long-term targets for utilities to achieve energy savings.

Similarly, Revenue Decoupling alone does not provide an incentive for the adoption of renewable energy or IPP agreements. To address this, policy makers should implement renewable portfolio standards (RPS) to require utilities to acquire a specified amount of renewable energy each year. This can be further targeted to IPP projects if policies require utilities to source a certain amount of their energy from third-party and/or Indigenous companies. RPSs can also be ramped up over time; for example, if the standard originally required utilities to obtain 2% of their energy from renewable sources, this percentage could increase annually until the desired level of renewable penetration is achieved. Both energy efficiency programs and renewable portfolio standards can be supported through applying Revenue Decoupling in tandem with PIMs.

Other PIMs could also be effective in limiting the disadvantages of Revenue Decoupling, such as a PIM for customer service to ensure public interest is upheld. Another method of mitigating against severe customer cost overruns is limiting rate increases to a set percentage adjustment per year.

While Revenue Decoupling is an effective method to reduce utility concerns towards energy efficiency and customer-owned generation, an issue of fairness is raised if these measures are not implemented evenly across customers. For example, if only a few large customers reduce their demand, rates will increase for everyone. Energy efficiency opportunities should be distributed equitably to all customers to mitigate such cost-shifting. Although the objective of Revenue Decoupling is to reduce sales risk for utilities, this risk could be shifted to consumers if energy efficiency adoption is not equitably implemented. Furthermore, with Revenue Decoupling, the issue of utility's favouring capital-intensive investments remains as revenue requirements are still established under the CoS methodology in rate applications. Implementation in tandem with other policies and utility reform actions can mitigate these impacts, as summarized in Table 9. Ultimately, any changes to rates should be clearly and transparently communicated to customers to avoid confusion and backlash over what may seem like unnecessary rate changes.

The roles and responsibilities of various stakeholders for successful Revenue Decoupling implementation are shown in Figure 13.

Government	• Define policy objectives and implement new legislation, if required • Mandate regulators to design regulations to implement policy objectives • Supply subsidies to mitigate potential price impacts to ratepayers
Utility Regulator	• Establish frequency of rate adjustment, degree of decoupling, and revenue adjustment method(s) • Verify utility performance based on degree of decoupling • Ensure rates are fair and reasonable for all customer classes and conduct structured reviews
Electric Utility	• Implement effective and fair energy efficiency programs and track their impacts • Monitor and report actual revenue vs expected revenue • Transparently communicate projected and actual rate impacts to customers

Figure 13. Government, regulator, and utility roles in Revenue Decoupling implementation

6.3.2 Revenue Decoupling — the remote context

As with many utility reform options, government subsidies complicate the implementation of a new rate mechanism, especially one that makes calculating customer rebates a more significant undertaking as Revenue Decoupling will mean that rates and hence subsidies are less predictable and easily predetermined. Subsidies should still be applied, if not increased, to ensure that customer risk is limited and any potential rate increases do not strain the already high cost of living in remote communities.

Additionally, rate and revenue adjustments will require consistent utility support to evaluate actual revenues against expected revenues and for revenue adjustments. This may not be a concern for utilities with a predominantly grid-tied customer base, but utilities that serve predominantly or exclusively remote communities already have limited internal capacity to support new initiatives. As such, Revenue Decoupling may have further implications for expanding utility capacity which may result in added costs to utility operations and an increased revenue requirement. The effects of these cost increases should be mitigated by efficiency improvements and more effective investments, enabled by Revenue Decoupling reform.

6.4 Alternative business model option 3 — Total Expenditure Approach (TOTEX)

The CoS model prioritizes capital expenditures over operational expenditures, as only capital costs are added to the rate base, leading to an increase in utility revenue and profits. With emerging grid technologies and software solutions, capital infrastructure may no longer be the most cost effective or technically best option. Utility business models need to be equipped to allow for a return on operating expenses when they are more appropriate than capital spending.

Non-wire alternatives are a growing market of services that reduce the need for capital spending on infrastructure (transmission or distribution) by the utility. For example, when distribution infrastructure upgrades are needed due to load growth, the traditional route would be to replace the transformer. An alternative to this could be a customer-owned battery that could supplement supply during peak demand hours. The utility would have to contract out this load management to the customer, meaning that an operational expense would be replacing the capital one. Although this allows for customer (in the remote context, Indigenous) ownership and is likely more economical, utilities under CoS regulation do not have an incentive to choose operational expenses over capital upgrades because they do not earn a return on OPEX.

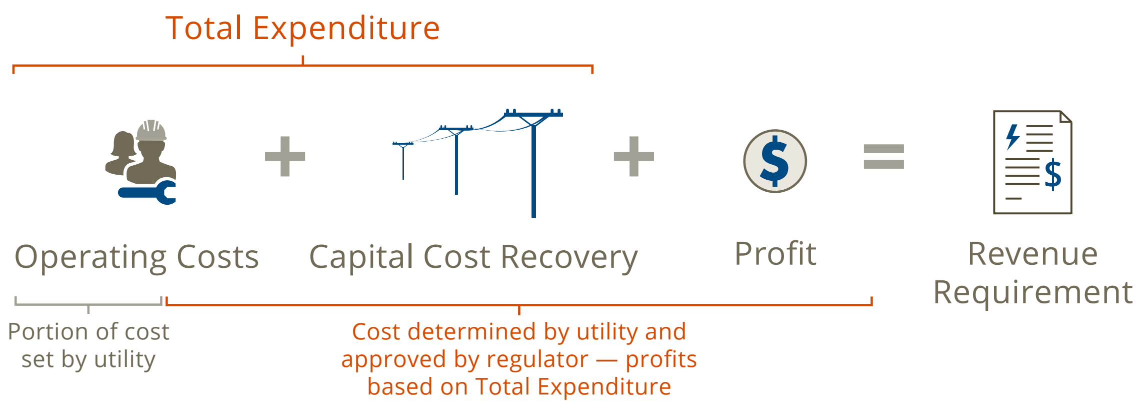


Figure 14. Impacts of TOTEX on revenue requirement

The Total Expenditure (TOTEX) approach allows utilities to earn a return on operating expenses, providing an incentive for new opportunities in grid modernization. Investment options are evaluated based on the total expenses over a project's lifetime, forcing utilities to evaluate assets in depth over their life cycle. To mitigate the potential for over-investment and expenditure inflation, regulators can set a cap on the amount of total expenditure that can be added to the rate base. Furthermore, regulators can set a predicted CAPEX/OPEX split to guide utilities in their investments and to incentivize a more efficient use of capital, especially when paired with PIMs that encourage utilities to target investment areas.

6.4.1 TOTEX — utility reform best practices

Access to high-quality, discrete data is essential to accurately assess whether capital or operational improvements are the most effective means of change. For example, in the case of a transformer upgrade, high-quality feeder and battery data are needed to ensure that the best option is chosen over project lifetime. In addition to program design decisions when implementing TOTEX, utilities should ensure that data needs can be met to ensure accurate decision-making.

When designing a TOTEX mechanism, regulators must specify what is and isn't included as an operating expense. In the U.K., regulators have specified TOTEX to be "all economical and efficiently incurred expenditure relating to a [utility's] regulated business."[43] This can include all costs, such as spare parts, support, overhead, operations, and maintenance. Government, regulator, and utility roles and

[43] London Economics International LLC, *Approaches to Utility Remuneration and Incentives,* presentation, September 17-19, 2019, 5. Available at https://www.oeb.ca/sites/default/files/Remuneration-DER-Stakeholder-Meeting-LEI-Presentation-20190828-v2.pdf

responsibilities when successfully implementing TOTEX accounting are shown in Figure 15.

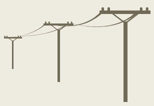
 Government	• Implement new legislation, if required • Supply subsidies to mitigate potential price impacts to ratepayers
 Utility Regulator	• Establish caps on expenditure to be added to the rate base • Set a predicted CAPEX/OPEX split • Specify what qualifies as an operating expense
 Electric Utility	• Evaluate expenses over project lifetimes to choose most economical and effective option • Collect sufficient data to assess effectiveness and design alternative approaches

Figure 15. Government, regulator, and utility roles in TOTEX implementation

6.4.2 TOTEX — the remote context

TOTEX encourages utilities to contract services with third parties, which presents new revenue and economic opportunities for Indigenous companies and communities. Under the current lens of inadequate Independent Power Producer policies, TOTEX allows utilities to earn revenue from these contracts, thus incentivizing them to offer better rates for Indigenous energy projects.[44] TOTEX is a method to increase utility investment into Indigenous companies and communities, spurring economic development in remote communities through the funding of Indigenous energy service providers and project developers.

However, data gathering is a concern in remote communities due to currently limited infrastructure and utility practices. TOTEX will require data collection infrastructure and software upgrades, and the corresponding upfront investment, to establish baseline costs for system operation such that future OPEX solutions can be accurately contrasted with CAPEX spending to choose the most economically efficient option. This may require government investment to provide upfront capital for these improvements.

TOTEX accounting is not widely applied in other jurisdictions, with the main example being U.K.'s RIIO program, as discussed in Section 6.7.3. As with any emerging system,

[44] Dave Lovekin and Dylan Heerema, *Comments on Qulliq Energy Corporation's proposed IPP policy* (Pembina Institute, 2019). https://www.pembina.org/pub/qulliq-ipp-policy

limited test cases mean higher risk; thus, pilot projects and further studies are needed. Utilities servicing predominantly grid-tied customers may be better suited for early adoption as they can more easily absorb unforeseen revenue impacts than a utility that mainly services remote areas could.

6.5 Alternative business model option 4 — Platform Service Revenues

As third-party energy service companies offering customers an extensive menu of new solutions to reduce their energy consumption become more common, a new market, accompanied with new market responsibilities, is emerging. Utilities can capitalize on their financial and engineering expertise and experience gained from already operating in remote communities to serve as a "platform" operator for third parties, where utilities coordinate third-party resources and services into the distribution system.

Beyond operating the grid, utilities can also offer innovate services to third parties. These value-add services could include data analysis and insights, transaction/billing assistance (charging customers for third-party services through utility monthly bills), connecting offerings with customers, and engineering support. In exchange, third parties pay platform fees, providing an additional revenue stream to utilities to mitigate any potential losses from reduced demand. Alternatively or additionally, regulators could approve a return on costs to utilities associated with integrating third parties to the grid if TOTEX accounting is implemented, to further incentivize utility support for platform operations.

Services offered by energy service companies could operate independently of utility platforms or said services could be offered directly by the utility; however, the greatest societal benefits are achieved when energy service companies operate in partnership with utilities, as shown in Table 8.

Table 8. Comparison of the Platform Service Revenue model vs. independent service provision

	Pros	Cons
Utility independently provides services	• Minimal startup costs • Can build on existing utility offerings/capabilities • Existing customer relationships	• Limited customer choice • Utilities are not incentivized to pursue service offers through CoS

	• Easy customer access to new services	• More risk adverse, less likely to innovate with new technologies
Utility as a **platform** for services offered by third-party	• New revenue opportunity for utilities • Enables third parties to enter market while benefiting from utility expertise and customer base • Leverage existing customer relationships • Easy customer access to new services • Innovation and new technology risk borne by third parties and not utilities (and hence customers) • More customer choice • Opportunity for Indigenous-owned businesses	• Possibility for higher prices compared to utility independently providing services because of platform fees
Third-party independently provides services	• More customer choice • Opportunity for Indigenous-owned businesses	• More difficult customer access to new services • Possibility for higher prices for services because of greater startup costs

Platform services allow utilities to leverage their market knowledge and business position. As new players enter the market, customers also benefit from the Platform Service Revenue model due to the more accessible decision-making opportunities, reshaping and expanding the historical utility-customer relationship from one of strictly billing. The exact effects of a Platform Service Revenue model depend on what role a utility chooses to adopt.

6.5.1 Platform Service Revenues — utility reform best practices

The services from which utilities are able to earn revenue should ultimately support policy objectives such as increasing renewable energy penetration. Regulators should establish a procedure for whether platform service costs are recovered through payments from third parties or an increase in utility return on equity, or both. In the later cases, regulators must establish how platform costs can integrate with a utility's rate base to form the overall revenue requirement.

Platform Service Revenue models are perhaps even more nascent than TOTEX, with application still in early stages in New York and limited across other states. However, if platform service revenues are solely tied to third-party fees and actual utility revenue remains consistent, risks to customers can be mitigated as the impacts to electricity rates will be minimal. Regardless, pilot projects and supporting studies are necessary to confirm the validity of applying platform service revenues to achieve utility reform objectives. Furthermore, early adoption should be done by utilities servicing a majority grid-tied customer base as the repercussions of any potentially unforeseen consequences are less severe than in a predominantly remote environment.

The roles and responsibilities of government, regulator, and utility parties when implementing the Platform Service Revenue model are shown in Figure 16.

Government	• Implement new legislation, if required • Supply subsidies to mitigate potential price impacts to ratepayers
Utility Regulator	• Establish new regulations for third-party electricity market participation • Establish regulations under which utilities are able to earn platform fees • Set process for evaluating platform fees • Assess utility performance in ensuring ratepayer service quality is maintained • Align new offerings with public interest
Electric Utility	• Determine the role of the utility in providing platform services • Propose platform fees • Develop new billing mechanisms • Communicate changes and any new service offerings to customers • Develop partnerships with third parties

Figure 16. Government, regulator, and utility roles in Platform Service Revenue implementation

6.5.2 Platform Service Revenues — the remote context

Having local knowledge is especially valuable for remote communities. This gives utilities a marketable service that can be monetized to support companies that may not have as much experience operating in remote communities. Alternatively, utilities can provide engineering support for Indigenous-owned companies that are perhaps well versed in the place-based context but lack insight into microgrid operations. This may lower a barrier to entry for Indigenous-owned businesses servicing remote communities.

As more renewable energy projects emerge in remote communities, project developers and owners are evaluating previously untapped revenue streams. Among these include renewable energy credits (RECs), which allow projects to monetize their energy generation. Each MWh generated by a project corresponds to one REC. RECs are bookkeeping tools that dictate who can 'claim' that they are consuming renewable energy, be that for regulatory or image purposes. The majority of RECs are certified by third parties, but currently, the certifying standard in Canada does not allow off-grid projects to provide RECs. One barrier to getting remote RECs certified is that certifiers require that generation data be verified by a neutral body. In the grid-tied environment, this is done by electricity regulators who already have good insight into how much power was generated. However, this is not the case in remote communities. Utilities servicing remote communities could offer generation tracking as a service to allow renewable energy projects to sell certified RECs.

The success of the Platform Service Revenue model in recovering revenues is partially tied to the size of the customer base, particularly if the utility is brokering services between third-party companies and customers. Due to the small number of customers in remote communities, this could limit the impact of utility brokerage. However, this does not limit the applicability of other value-add services a utility may provide third parties.

6.6 Summary of alternative utility business model reforms

Four avenues for utility reform were identified as applicable in the remote community context. A summary of the advantages and disadvantages of each utility reform option are shown in Table 9.

Table 9. Utility business model reform summary of advantages and disadvantages

Advantages	Disadvantages	Addressing disadvantages
Performance Incentive Mechanisms (PIMs) Regulators implement trackable metrics tied to utility performance. Performance corresponds to financial incentives or penalties in the form of changes to a utility's return on equity or direct incentives / penalties to the utility.		
Opportunity to align utility operations with climate policy and reconciliation goals. Motivates utility spending towards programs that were otherwise not financially incentivized. Increases information available to regulators and other stakeholders from PIM tracking and reporting.	Complicated for regulators and utilities to establish and operate. Performance target setting is difficult: If targets are not properly set, arbitrary swings in compensation and/or perverse incentives may result. If targets require complicated measurement and verification, quantifying success can become uncertain. Requires significant additional capacity from the utility and regulator to support PIM projects and for reporting and validation.	Governments need to appropriately fund regulators such that they can carefully design programs. Pilot projects are required to test targets. Utilities should have adequate resources and capacity to adjust for the additional program requirements.

Advantages	Disadvantages	Addressing disadvantages
Revenue Decoupling Units of energy sold do not impact actual revenue as customer rates and potentially a utility's revenue requirement can be adjusted periodically. A limit is set on the magnitude of the adjustment to restrict rate increases on customers. General Rate Applications are still conducted periodically to adjust rates and the revenue requirement under regulator purview.		
Removes utility hesitancy to support renewable energy and energy efficiency projects that would have reduced their revenue under CoS. Reduces utilities revenue loss risk to better align business practices away from growing sales and towards renewable energy and energy efficiency.	Does not address incentives for large capital investments to grow the rate base. Does not motivate utilities to the choose lowest-cost or most effective solutions for meeting utility reform goals if they can earn a higher return by meeting demand with investments in new power plants and power lines.	Implement in tandem with other utility reform measures such as TOTEX to mitigate capital investment incentives and well-designed PIMs to incentivize utilities to choose the most effective solutions.
	Does not provide an incentive for the adoption of energy efficiency, renewable energy, or IPP agreements.	Ensure EERS and/or RPS policies are already in place. RPSs should specifically require utilities to procure a set amount of renewable energy rather than exclusively operate self-generation.
	Fairness and cost shifting concern if EE and customer-owned generation are not evenly implemented across consumers.	Implement equitable and accessible clean energy programs in tandem with Revenue Decoupling.
	Results in rate increases due to declining revenue regardless of whether this decline is due to clean energy or not.	Cap rate increases to mitigate impacts.
	Locks in utility revenue and shifts energy sales risks to consumers.	Cap rate increases to mitigate impacts.

Advantages	Disadvantages	Addressing disadvantages
Total Expenditure Approach (TOTEX) Utilities earn a return on both capital and operating costs, incentivizing them to choose the most economical option.		
Makes utilities indifferent between CAPEX (traditionally earning a rate of return) and OPEX (traditionally not earning a rate of return) solutions such that they are incentivised to choose the best option. Allows utilities to earn a return on IPP contracts, creating opportunities for Indigenous companies and communities to develop renewable energy projects.	Limited application in other jurisdictions introduces risks for early adopters.	Early adoption should be done by utilities who serve predominantly grid-tied customers as they are less impacted by potentially unforeseen consequences.
	Requires data collection and software upgrades.	Utility infrastructure upgrades may require government investment and grants. TOTEX allows utilities to contract third parties for these data and software needs, subsidies should be applied to mitigate ratepayer impacts.
Platform Service Revenues Utilities serve as a "platform" operator for third-party energy service companies that can supply energy in addition to other energy-related services to customers, coordinating energy resources into the distribution system in exchange for fees the third parties pay.		
Win-win-win scenario for the utility, third parties, and customers: utilities secure a new revenue stream, barriers to entry are lowered for third parties and customers get expanded services. Opportunity for off-grid RECs, a new revenue stream for renewable energy project developers in remote communities.	Utilities servicing remote communities have a small customer base which may mean that revenues from other services are limited.	Although the impacts of a Platform Service Revenues model may be small in remote communities, this model still provide a multitude of benefits.
	Limited application in other jurisdictions introduces risks for early adopters.	Early adoption should be done by utilities who serve predominantly grid-tied customers as they are less impacted by potentially unforeseen consequences.

Advantages	Disadvantages	Addressing disadvantages
	Possibility for higher customer rates compared to utility independently providing services because of platform fees.	Customers can lower their energy bills (accounting for these potentially higher prices) through new energy efficiency and management service offerings.

6.7 Utility reform options in action

Utility reform options have been applied in grid-tied jurisdictions around the world. Governments, regulators, and utilities can learn from several successful examples to adapt and implement changes in the remote community context. Just as with grid-tied utilities, utilities serving remote communities must evolve past the old model of maintaining profitability solely by acquiring more assets and selling more electricity to recoup past capital expenditure costs, and instead embrace profitability, new services and different measures of "success" through meeting environmental, social, health, and climate resilience targets. Table 10 outlines utility reforms that have been implemented in selected case studies in North America and the United Kingdom. Details on each case study are presented below.

Table 10. Utility reform case studies

	Ontario (RRF)	New York (REV)	UK (RIIO)	Hawaii (PBR)
PIMs	✓	✓	✓	✓
Revenue Decoupling	✓		✓	
TOTEX			✓	
Platform Service Revenues		✓		
Other	Innovation Sandbox		Innovation Link	

6.7.1 Ontario: Renewed Regulatory Framework (RRF)

The Government of Ontario has begun implementing utility reform options that have helped the grid-tied electricity system advance beyond CoS regulation. The province's Renewed Regulatory Framework (RRF) allows utilities to choose from a menu of performance incentive mechanisms. PIMs are centred around customer preferences (service quality and customer satisfaction), operational effectiveness (safety, system reliability, asset management, and cost control), public policy responsiveness (conservation and demand management, renewable energy), and financial performance (financial ratios for liquidity, leverage, and profitability).[45]

To decouple rates from utility revenues, the regulator (Ontario Energy Board (OEB)) implemented a fixed distribution charge for residential electricity customers to replace the former usage-based distribution charge. This increases the amount of revenue collected through the fixed rate and reduces the amount of revenue collected through the usage rate. This option allows the distributor to collect the same total revenue from residential customers as they did through the usage rate; however, the fixed charge will increase the distribution charge for low energy users and decrease it for high energy users.[46] Distribution utilities in Ontario can choose from three options for setting customer rates. These multi-year rate plans ensure utility rate cases occur at set time periods and base utility compensation on forecasted, rather than historical, expenditures. Each option is subject to a regulatory review if the utility's annual reports show that the utility is not achieving the agreed-upon PIMs. To ensure fair rates, the OEB continues to consult with stakeholders on instituting additional rate designs such as multi-unit residential rates, as well as communicating changes to customers.[47]

To incentivize innovation, the OEB provides support for new ideas through the Innovation Sandbox. Pilot projects, if approved, can be deployed to test ideas under temporary exemption from regulations.[48] Through this process, the IESO and Alectra Utilities piloted a two-year project to test how competition and local resource options can be used to support electricity reliability and affordability. The project also aims to "better understand the potential of using DERs in place of traditional infrastructure by enabling them to operate in real-world applications."[49] The capacity auction allowed nine energy and capacity service providers to provide a total of 15,000 kW of distributed, locally based electricity capacity to the grid.[50] An upcoming joint

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[45] *Approaches to Utility Remuneration and Incentives,* 5.

[46] Ontario Energy Board, *Board Policy – A new Distribution Rate Design for Residential Electricity Customers* EB-2012-0410, 3. https://www.oeb.ca/sites/default/files/uploads/OEB_Distribution_Rate_Design_Policy_20150402.pdf

[47] Ontario Energy Board, *Board Policy – A new Distribution Rate Design for Residential Electricity Customers* EB-2012-0410, 27.

[48] Ontario Energy Board, "How does the Innovation Sandbox work?" https://www.oeb.ca/_html/sandbox/process.php

[49] IESO, "IESO York Region Non-Wires Alternatives Demonstration Project," 2021. https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/IESO-York-Region-Non-Wires-Alternatives-Demonstration-Project

[50] IESO York Region Non-Wires Alternatives Demonstration Project, *Local Capacity Auction – Post Auction Report* (2021). https://yrdemo.com/file/LocalCapacityAuction-PostAuctionReport-Year2_V1.0.pdf

Innovation Sandbox project by the IESO and OEB will also test how to derive value from DERs.[51] This project will assess the potential to avoid costly system upgrades by integrating DERs in the York Region, where electricity demand is expected to exceed system capability in the next 10 years.[52]

Ontario's open wholesale competitive electricity market allows for greater opportunity for change at the regulator and utility levels without the requirement of legislative changes. The OEB instigated Ontario's shift from CoS to multi-year rate plans, Revenue Decoupling, and PIMs with the goals of reducing the regulatory burden associated with reviewing more utility rate cases, establishing minimum service quality and reliability standards, and providing greater incentives for cost reduction and productivity gains.[53]

6.7.2 New York: Reforming the Energy Vision (REV)

In response to the destruction of Superstorm Sandy in 2012, the New York Public Service Commission (PSC) initiated a proceeding the next year to update utility regulation to meet the needs of the evolving electricity sector.[54] The plan, called "Reforming the Energy Vision" (REV), fundamentally changes the distribution utility's role from owning and operating a passive distribution network to actively facilitating a network that that accommodates customer-side DERs, smart grid devices, and new energy services.[55]

To accommodate this new model, PBRs were introduced to allow and incentivize utilities to generate revenue from providing services outside the traditional CoS model of selling more electricity. In addition to multi-year rate plans, which New York has implemented since the mid-1990s, the PSC has introduced PIMs and innovative compensation mechanisms to accelerate renewable energy development while ensuring system reliability.

REV also incorporates Platform Service Revenues to develop a market-based platform through which utilities can sell products and services that advance the state's goals of

[51] Ontario Energy Board, "IESO/OEB Joint GIF/OEB Innovation Sandbox Targeted Call." https://www.oeb.ca/_html/sandbox/index.php

[52] "IESO York Region Non-Wires Alternatives Demonstration Project."

[53] M.N. Lowry, J. Deason, M. Makos, and L. Schwartz, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities* (U.S. Department of Energy, 2017), 6.30. https://gmlc.doe.gov/sites/default/files/resources/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf

[54] Navigant, *Starting a conversation: Is there flexibility to adapt Canada's current utility regulation landscape?* (2018), 6. https://electricity.ca/wp-content/uploads/2018/10/Navigant-Flexibility-to-Adapt-Regulation.pdf

[55] *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, 6.16.

integrating DERs to meet GHG reduction targets.[56] Utilities receive revenues from performing required services, as well as offering value-added utility services such as data analysis and engineering services for microgrids.[57] The PSC established standards for evaluating and approving platform service revenues, as new opportunities will continue to emerge as the platform market evolves to meet system and customer needs.

Because of REV's focus on DERs, regulations were changed to allow utilities to retain earnings on previously approved, traditional utility capital projects included in base revenue, if the utility demonstrates that demand-side initiatives displaced the capital project. Further, to ensure fair compensation for DER projects, the PSC established the Value of Distributed Energy Resources (Value Stack), which compensates DER projects based on when and where they provide electricity to the electric grid.[58] The Value Stack provides bill credits to DER producers and offers additional incentives for community generation. "Earnings Adjustment Mechanisms", the state's term for PIMs, focus on outcomes, rather than on utility inputs or achievement of program targets. These include system efficiency, energy efficiency, and interconnection of DER and storage projects.[59]

REV prioritizes DER and non-wires alternatives by requiring utilities to propose at least one non-wires alternatives solution instead of infrastructure investments to meet new reliability needs.[60] When utility Consolidated Edison (ConEd) proposed constructing a new electrical substation, the regulator ordered ConEd to define the need for the substation and allowed third parties to propose solutions. Ultimately, ConEd delayed construction of the substation in favour of implementing a portfolio of DERs.[61]

[56] *Navigating Utility Business Model Reform,* 59.

[57] State of New York Public Service Commission, *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework*, 2016, 41. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D6EC8F0B-6141-4A82-A857-B79CF0A71BF0}

[58] New York State Solar Program (NY-Sun), "The Value Stack." https://www.nyserda.ny.gov/all-programs/programs/ny-sun/contractors/value-of-distributed-energy-resources

[59] *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, 6.18.

[60] State of New York Public Service Commission, *Order Adopting Regulatory Policy Framework and Implementation Plan* Case 14-M-0101, February 26, 2015, 130. https://www3.dps.ny.gov/W/PSCWeb.nsf/All/FCFC9542CC5BE76085257FE300543D5E?OpenDocument

[61] Herman K. Trabish, "Energy Vision framework remains both vital and unfinished, analysts say," *Utility Dive*, December 9, 2021. https://www.utilitydive.com/news/new-yorks-landmark-reforming-the-energy-vision-framework-remains-both-vita/610015/

New York's REV program shows how utilities and regulators can proactively and successfully address the challenge of integrating increased DERs into electric grids. It demonstrates that regulatory systems must be designed with enough flexibility to allow utilities to adapt to market and technological changes. REV also shows that successfully integrating DERs requires a localized, complex pricing structure that involves significant time, resources, and expertise to properly develop and implement.

6.7.3 United Kingdom: Revenue = Incentives + Innovation + Outputs (RIIO)

Starting in 2013, the Office of Gas and Electricity Markets (Ofgem), the United Kingdom's utility regulator, instituted Revenue = Incentives + Innovation + Outputs (RIIO) in response to suspicion that some utilities misrepresented their CAPEX needs in CoS rate cases.[62] RIIO addresses changing market conditions through a combination of several utility reform options, including multi-year rate plans, TOTEX, PIMs, Revenue Decoupling, and "Innovation Link", an infrastructure fund that allows utilities to test pilot projects and technologies without the risks associated with permanent program implementation.[63]

PIMs are based on meeting system reliability and performance standards, ensuring customer satisfaction, maintaining adequate operation of system components, and reducing air emissions.[64] To decouple utility revenues from electricity sales, Ofgem employs revenue caps that refund or charge customers for variances between actual and allowed revenue.[65] When combined with this revenue cap, the TOTEX model of allowing rate of return on both CAPEX and OPEX as one regulatory asset incentivizes utilities to seek the most cost-effective solution for the utility as well as their customers.[66] A pioneering component of RIIO is the Innovation Link, which allows energy innovators to test proof-of-concept for products, services, and utility reform options that do not fit neatly into existing regulatory structures.[67] In its first two years, the program funded over 260 innovative pilot projects.[68] To advance this program and continue evolving the

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[62] *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, 6.38.

[63] Advanced Energy Economy Institute, *UK's RIIO – A Performance-Based Framework for Driving Innovation and Delivering Value*, case study, 1. https://info.aee.net/hubfs/RIIO%20Case%20Study%20Final%20.pdf

[64] *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, 6.41.

[65] *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, 6.42.

[66] *UK's RIIO – A Performance-Based Framework for Driving Innovation and Delivering Value*, 1.

[67] *Starting a conversation: Is there flexibility to adapt Canada's current utility regulation landscape?,* 8.

[68] *UK's RIIO – A Performance-Based Framework for Driving Innovation and Delivering Value*, 3.

RIIO model, follow-up funding could be allocated to permanently implement tested and proven projects.

In the first annual report on RIIO, Ofgem reported that most utilities were spending less than their allowance while simultaneously improving overall performance. On the whole, utilities decreased their business carbon footprint, improved interconnection times, and excelled in customer satisfaction.[69] RIIO demonstrates the effectiveness of PIMs in aligning utility and customer outcomes, and the Innovation Link shows how regulatory reform can be advanced through small, incremental changes.

6.7.4 Hawaii: PBR Framework

Hawaii's renewable portfolio standard requires 100% of the state's electricity to come from clean energy sources by 2045.[70] Because of the state's reliance on imported fuel oil for electricity, Hawaii's utility rates are the highest in the United States.[71] Coupled with the island's abundance of sunshine, this has motivated households to pursue rooftop solar installations to reduce their electricity costs. This trend initially resulted in conflicts between utilities and their customers; however, in 2018, Hawaii's utility regulator moved to completely overhaul the existing CoS regulatory structure to incentivize utilities to cut costs while achieving climate goals.[72]

Hawaii's PBR Framework officially went into effect on June 1, 2021. It introduces a portfolio of PBRs, including financial incentives as well as penalties, aimed at achieving the state's clean energy goals. PIMs include faster interconnection timelines to facilitate renewable energy projects, an energy efficiency program to "provide low-to-moderate income customers with opportunities to better manage their energy consumption," and an incentive for deploying advanced metering infrastructure.[73]

While the PBR Framework's multi-year rate plan reduces regulatory burden by lengthening rate case intervals from three to five years, it also introduces a risk of increasing customer electric bills if it results in less attention being paid to how the

[69] *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, 6.44.

[70] Hawaii State Energy Office, "Securing the Renewable Future." https://energy.hawaii.gov/renewable-energy

[71] Julia Simon, "Biden's climate agenda is stalled in Congress. In Hawaii, one key part is going ahead," *NPR*, January 15, 2022. https://www.npr.org/2022/01/15/1066578157/bidens-climate-agenda-is-stalled-in-congress-in-hawaii-one-key-part-is-going-ahe

[72] "Biden's climate agenda is stalled in Congress. In Hawaii, one key part is going ahead."

[73] State of Hawaii Public Utilities Commission, "Performance Based Regulation (PBR)." https://puc.hawaii.gov/energy/pbr/

utilities are spending money.[74] To mitigate potential rate impacts on customers, the PBR Framework includes a Customer Dividend that will provide an estimated $69.9 million in rate reductions through 2025.[75]

Having been implemented for only a few months, it is too soon to measure the success of Hawaii's PBR Framework. The decision to adopt the PBR Framework culminated a two-and-a-half year process that involved consultations with a diverse set of stakeholders, collaboration, and iteration to design PBR targets that aligned with the state's climate goals while addressing the challenges of high costs for imported fuel and high customer demand for renewable energy. This experience can provide lessons learned for other jurisdictions developing PBR programs of their own. Future program assessments will determine how successful Hawaii's framework is at encouraging renewable energy development while keeping customer electricity costs low.

[74] Cara Goldenberg, "Five Lessons from Hawaii's Groundbreaking PBR Framework," February 8, 2021. https://rmi.org/five-lessons-from-hawaiis-groundbreaking-pbr-framework/

[75] "Performance Based Regulation (PBR)."

7. Projected impacts of utility business model reform

7.1 Impacts to utility finances and electricity rates

Each of the four utility reform alternatives assessed have varying impacts on utility financials and hence electricity rates. The exact effects that implementing each model will have on utility financials depends strongly on the robustness of utility reform implementation — as highlighted in Section 6, seemingly small changes can have large impacts on the overall success of implementation. Furthermore, changes to revenues are dependent on which utility reform actions are implemented. As such, the impacts discussed are very high level; specific utility financial impacts will require evaluation on a case-by-case basis depending on the utility, jurisdiction, and which measures are implemented.

Regarding how rates are structured, the utility reform pathways studied primarily change how the utility generates revenue. When properly implemented, they should have minimal impacts on customer rate structures. In other words, for the utility reform options that do not implement rate design reform, the amount of revenue collected changes and there may now be multiple avenues for utilities to collect this revenue. At the same time, the customer billing remains unchanged in that bills are still comprised of a fixed monthly rate plus a per kWh charge.

Although rate structures may not change, rates themselves may increase or decrease due to utility reform. The impacts of utility reform on rate changes are dependent on the mechanisms applied and the effectiveness of their design. In the remote context, government subsidies will still be required to issue incentives, such as for PIMS, or to protect ratepayers from potential increases under Revenue Decoupling. Utility reform in remote communities means stressing the importance of mitigating rate impacts. However, this needs to be balanced with aligning utility priorities with utility reform objectives.

7.1.1 PIMs

If PIM reward mechanisms are tied to ROE, PIMs can result in either increases or decreases in rates. Electricity rate impacts can be minimized by tying PIMs to direct incentives. These minimal rate impacts mean that customer incentives for consumption and demand reduction remain unchanged in terms of direct electricity bill savings. For example, while a PIM targeted at increasing energy efficiency will not change the amount a customer saves from lowering their energy bills, it would potentially provide customers with more avenues for implementing energy efficiency measures through utility-run programs.

PIMs should positively affect utility financials, providing a more secure revenue stream for utilities to adapt to the customer and policy objectives established through PIMs. This will require subsidy support, as utilities will need a replacement revenue stream to minimize rate impacts on customers.

7.1.2 Revenue Decoupling

Revenue Decoupling is classified as rate design reform, as shown in Table 6, but does not change how customers are billed. However, it does change how rates are calculated by the utility. Revenue Decoupling results in increased volatility of electricity rates, meaning that rates may fluctuate on a monthly basis. Revenue Decoupling may be the utility reform option that has the greatest impact on customers. To mitigate this impact, it may require the greatest and most continuous support from subsidies. Additionally, as noted in Section 6.3.1, implementing accessible energy efficiency programs to reduce customer bills should also be undertaken.

Utility revenues under Revenue Decoupling should match costs fairly closely. However, proper Revenue Decoupling implementation also caps rate increases, meaning that if utility spending increases or revenue decreases above or below this cap, utility revenues and costs will diverge. As such, Revenue Decoupling requires utilities to be cognizant of overspending and still run efficiently to ensure healthy utility financials.

7.1.3 TOTEX

Of the reform options evaluated, TOTEX may have the least impact on electricity rates and utility financials, at least in the short term. TOTEX allows utilities to choose the most economically efficient method of addressing customer needs. This would decrease spending in the long term, lowering electricity rates. However, TOTEX requires utilities to collect baseline data to evaluate OPEX investments, meaning that changes from TOTEX will not be immediate while utilities establish business-as-usual costs.

7.1.4 Platform Service Revenues

Platform Service Revenues may result in changes to customer billing if a utility decides to broker services between third parties and customers. However, if utilities are not brokering services, then no rate design reform is implemented. A high-level overview of Platform Service Revenues for a hypothetical utility rate structure, with examples of possible third-party services, is shown in Table 11.

Table 11. Platform Service Revenue potential impacts to electricity rates

Base Electricity Rates		Optional Adders (Third-Party Services)	
Base rate	$15/month	Rent a battery to increase reliability	+$50/month
First 700 kWh	$0.30/kWh	Purchase 100% renewable energy	+$0.01/kWh
Consumption above 700 kWh	$0.60/kWh		

Platform Service Revenues create a new revenue stream for utilities, making utility financials more robust in the energy transition. The magnitude of impact will depend on customer uptake of third-party services and may be more minimal in remote communities due to small customer bases.

7.2 Social and community impacts

The current state of utility operation and regulation is a major barrier that communities face when trying to transition to cleaner, more efficient energy systems. As such, implementing a utility business model that supports renewable energy and energy efficiency uptake lowers this barrier, allowing communities to reap the associated benefits of Indigenous-owned renewable energy systems, including greater energy security, energy sovereignty, positive economic impacts, and community pride. Utility reform options that directly support Indigenous ownership and economies provide direct means for utilities to advance reconciliation.

The positive economic impacts from improving access and opportunities for renewable energy generation include not only the long-term cost savings of getting off diesel, but also the economic opportunities of implementing clean energy projects, from the businesses that spearhead projects, the individuals hired for construction, and the community members employed long term for operations and maintenance. Platform Service Revenues present opportunities for Indigenous entrepreneurs to provide services and more accessibly enter the market and benefit from long-term utility partnerships to provide energy services. Furthermore, revenue generated from IPP contracts and the possible retail of environmental attributes can be used in community investment funds which further stimulate economic development opportunities in remote communities.

Revenue Decoupling and PIMs specifically may incentivize utilities to implement funding through energy efficiency programs. Depending on the design, these programs can support general energy efficiency upgrades and also enable homeowners and public housing associations to perform deep retrofits in aging, inadequate and often unhealthy housing infrastructure. Through these programs, lower energy costs and improved building energy efficiency will result in greater energy and cost security — crucial quality of life aspects for remote, northern communities.

7.3 Environmental impacts

A significant environmental impact of reducing diesel consumption is mitigation of GHG emissions. Although emissions from diesel in remote communities accounts for a very small fraction of Canada's overall GHG emissions, remote communities, particularly those in Canada's north, will be some of the most affected by climate change.[76,77] Communities need avenues to address climate impacts autonomously. Besides carbon, reducing diesel emissions also reduces the detrimental health impacts from other airborne pollutants.[78]

Beyond air pollutants, transporting and storing diesel to and in remote communities poses a huge risk: since the 1970s, over 9.1 million litres of diesel has been spilled in Nunavut and the Northwest Territories.[79] This is a major threat to ecosystems and drinking water supplies, which poses another avenue for health risks associated with diesel fuel, potentially resulting in more costs to deliver emergency water supplies to

[76] Inuit Tapiriit Kanatami, National Inuit Climate Change Strategy (2019), 2-3. https://www.itk.ca/wp-content/uploads/2019/06/ITK_Climate-Change-Strategy_English.pdf

[77] Nichole Dusyk and Isabelle Turcotte, *All Hands on Deck: An assessment of provincial, territorial and federal readiness to deliver a safe climate* (Pembina Institute, 2021), 39. https://www.pembina.org/reports/all-hands-on-deck.pdf

[78] Government of Canada, "Human Health Risk Assessment for Diesel Exhaust - summary." https://www.canada.ca/en/health-canada/services/publications/healthy-living/human-health-risk-assessment-diesel-exhaust-summary.html

[79] Jimmy Thomson, "How can Canada's North get off diesel?", *The Narwhal*, February 11, 2019. https://thenarwhal.ca/how-canadas-north-get-off-diesel/

these communities.[80] Cleaning up these spills is another cost incurred due to diesel use. These costs and environmental impacts would be mitigated with renewable energy to replace diesel use, and energy efficiency to reduce the volume of energy consumed.

Opening opportunities to diversify energy supply in remote communities is also a factor to climate change adaptation — many communities rely on winter roads to truck in fuel. These ice roads are becoming less reliable with shortened and warmer winters. Having a greater mix in energy supply and more opportunities for energy storage and efficiency is a hedge against potential future supply chain shortfalls of diesel due to climate change.

[80] Global News, "Iqaluit water crisis: State of emergency declared as city receives 1st water shipment," media release, October 14, 2021. https://globalnews.ca/news/8267135/iqaluit-water-crisis-state-shipment/

8. Summary, recommendations, and conclusions

Reforming how utilities do business in remote communities is essential. As governments implement climate action policies, utilities are taking on new areas of responsibility. Whether it is increased government climate and energy policy action, a decarbonized grid, developing equitable energy systems that prioritize Indigenous involvement and respect Indigenous rights, or customer demand for more services and better experience, utility reform is a tool for these new responsibilities to be realized.

Utilities operating in grid-tied jurisdictions have started to respond to these new responsibilities by exploring and implementing some innovative utility business models. The exploration of these reform options for the most part has required the support of (and in some cases, lead from) governments and regulators — with government climate and energy policies often being the catalyst that kickstarts reform research and exploration. Since electricity regulation for the most part is still rooted in the traditional mandate of utilities to provide "safe, affordable and reliable power," governments responding to climate change through the development of climate and energy policies are starting to realize the disconnect and problematic isolation between climate objectives and traditional electricity regulation. This manifests as tension between governments, electricity regulators, and utilities; solutions such as utility reform are needed to address this disconnect. Without evolution of utility business models through the reform options presented here, utilities will continue to inadequately respond to climate policies, Indigenous rights, and customer's expressed needs.

These pressures for reform are amplified by community desires in conjunction with federal and sometimes provincial targets to reduce diesel consumption, net-zero electricity grid goals, a handful of provincial / territorial climate plans, and the pursuit of energy independence and sovereignty by many Indigenous communities. Indigenous businesses, entrepreneurs, and communities are bringing forth solutions for better and more efficient housing and renewable energy generation by asserting their rights and appropriate place in their community's clean energy transition. This intensifies the challenges utilities are facing around lost revenue from decreased electricity sales and is even bringing into question the role of regulated utilities in these communities.

Since very little, if any, competition exists in electricity markets in remote communities, there is little motivation for utilities to explore new ways of operating. Utility behaviour for the most part defaults to protecting utility interests with little consequences for this inaction. To change the status quo and open opportunities such that communities and utilities can participate fully in the clean energy transition, utility reform is needed. Utility reform creates new pathways for all stakeholders to explore existing and emerging policy and customer priorities not currently satisfied under the Cost-of-Service model and address regulatory restrictions imposed on utilities operating within the unique remote community context.

8.1 Utility reform options for remote communities

Each of the four utility reform options explored in this report targets a different combination of utility reform objectives, as shown in Figure 17. PIMs and Revenue Decoupling satisfy the most reform options and are particularly effective in combination at removing utility reluctancy towards energy efficiency and customer-owned renewable energy projects.

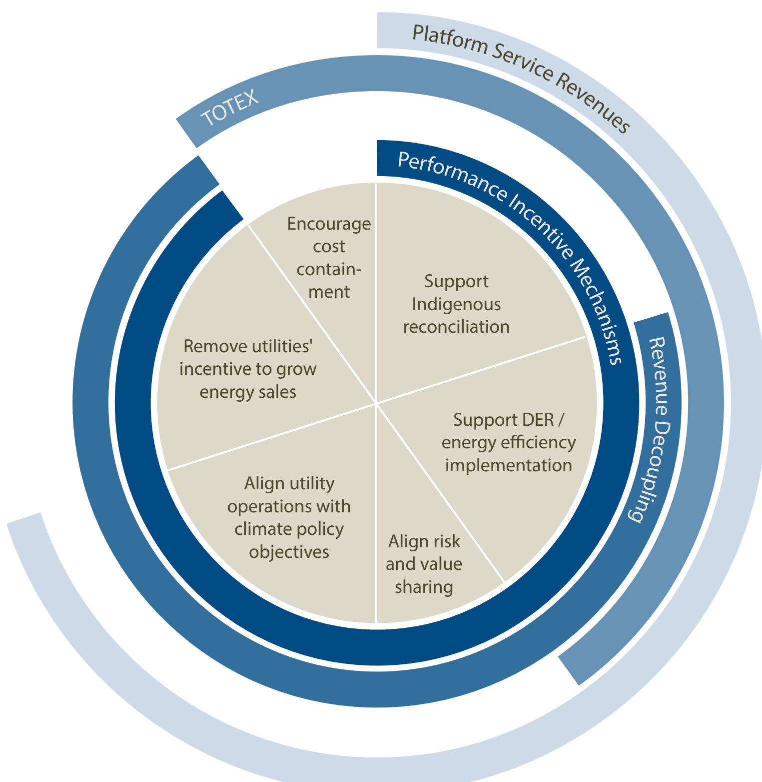


Figure 17. Utility business model reform options satisfying reform objectives

Satisfying all or most of the identified reform objectives will require extensive reform and change, but this would likely overwhelm both regulator and utility capacities. Instead, utility reform should be approached gradually and incrementally, where reform methods that are the least disruptive are implemented first. Policymakers, regulators, and utilities should collectively define what reform options are best suited for the priorities and objectives of their jurisdiction and ensure that any disadvantages or challenges faced from reform implementation are understood and addressed accordingly.

The impacts and intricacies of implementing each individual utility reform option should be thoroughly evaluated when identifying how utility reform options are put into action. Some reform options are best applied in parallel to counter any challenges created. For example, the shortfalls of Revenue Decoupling (namely that Revenue Decoupling does not address capital investment incentives and does not motivate utilities to choose the most cost effective or efficient investment solution) can be addressed by establishing PIMs and/or TOTEX accounting concurrently. Several different approaches including case studies, trials, and innovation sandboxes can be used to begin exploring utility reform.

The main advantages of the four utility reform options evaluated are summarized in Table 12.

Table 12. Advantages of utility reform options.

UBM	Advantages
Performance Incentive Mechanisms (PIMs)	Opportunity to align utility operations with climate policy and reconciliation goals. Motivates utility spending towards programs that were otherwise not financially incentivized. Increases information availability to regulators and other stakeholders from PIM tracking and reporting.
Revenue Decoupling	Removes utility hesitancy to support renewable energy and energy efficiency projects that would have reduced their revenue under CoS. Reduces utilities revenue loss risk to better align business practices away from growing sales and towards renewable energy and energy efficiency.
Total Expenditure Approach (TOTEX)	Makes utilities indifferent between CAPEX (traditionally earning a rate of return) and OPEX (traditionally not earning a rate of return) solutions such that they are incentivised to choose the best option.

	Allows utilities to earn a return on IPP contracts, creating opportunities for Indigenous companies and communities to develop renewable energy projects.
Platform Service Revenues	Win-win-win scenario for the utility, third parties, and customers: utilities secure a new revenue stream, barriers to entry are lowered for third parties and customers get expanded services. Opportunity for off-grid RECs, a new revenue stream for renewable energy project developers in remote communities.

One strategy for staged utility reform would be to implement PIMs and Revenue Decoupling first, followed by TOTEX accounting and/or Platform Service Revenues. PIMs require a large degree of utility reform support. However, they are the most effective at satisfying multiple utility reform objectives, can be specifically designed to support government policy goals, and have been widely applied in other jurisdictions.

Figure 18 shows how utilities could meet their revenue requirement if utility reform approaches use this staged approach. The diagram gives a vision of how a utility of the future's revenue requirement is no longer entirely dictated by the traditional CoS model, allowing it to meet new and emerging responsibilities. This utility of the future operates under "CoS-plus" ratemaking and revenue streams, allowing for more opportunities to facilitate a just energy transition and support Indigenous reconciliation.

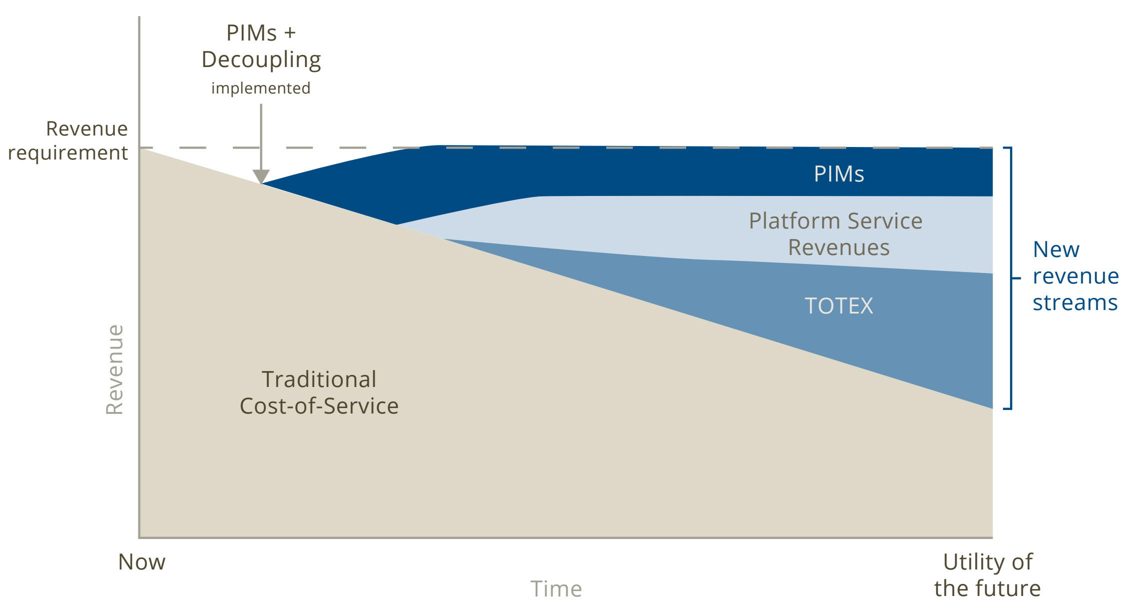


Figure 18. Utility business model reform impacts on utility revenue

Identifying what specific reform options should be implemented in each jurisdiction is a matter of prioritizing utility reform objectives while acknowledging the strengths and shortfalls of each reform option and the jurisdiction's market structure. In particular, Platform Service Revenues may be better suited to deregulated markets where many utility retailers could partner with third parties and where third parties would have fewer approval processes to meet before providing services.

If the goal of reform is to meet all utility reform objectives, all four utility business model alternatives should be applied using the staged approach. If encouraging cost containment is not a priority objective, then implementing TOTEX reform is not the best option. Prioritizing reform objectives will require direction from provincial and territorial climate and energy targets, in addition to updating regulator and utility mandates. Updating mandates should be a collaborative process between governments, regulators, and utilities to best reflect shared priorities for utility reform.

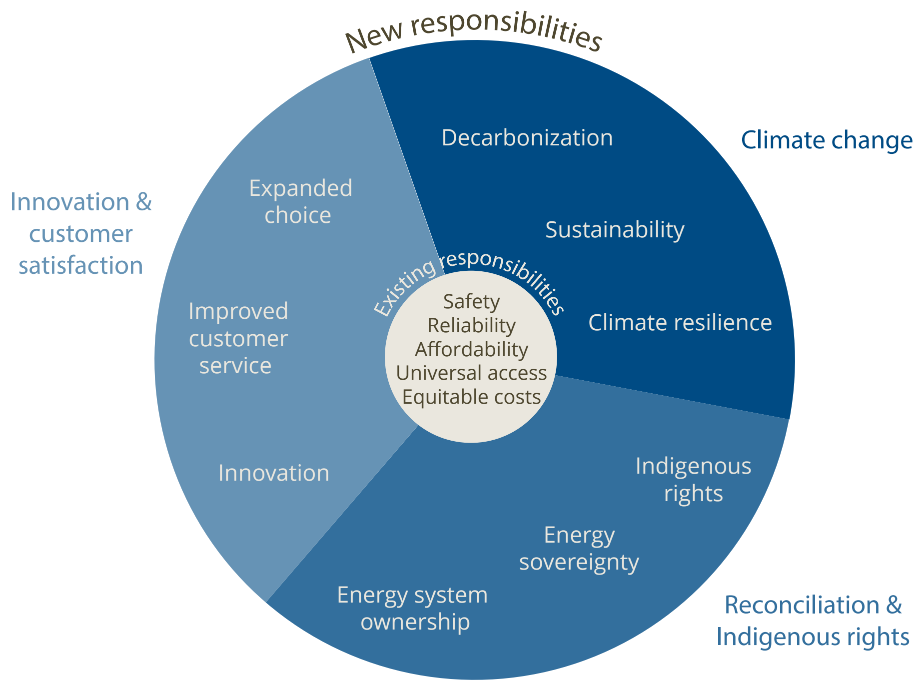
As such, no direct recommendations specific to the electricity market and regulatory framework in each remote community jurisdiction are presented in this report. Providing specific guidance on reform recommendations would require a deeper and collaborative discussion with all stakeholders to define and prioritize reform objectives based on government and utility emerging responsibilities.

8.2 A framework for approaching utility reform

The following framework is presented as a guiding aid for a working group comprised of members from government, regulators, utilities, and Indigenous communities to approach and consider utility reform opportunities. This simple process outlined below will help utilities and other stakeholders orient and determine what first steps are needed when determining if and how utility reform can help address their challenges.

Utility reform approach framework

1. List the new responsibilities and sub-responsibilities that are emerging for utilities and identify how they can be categorized, based on the figure below, into climate change; reconciliation and Indigenous rights; and innovation and customer satisfaction.



2. With input from all stakeholders, prioritize these new responsibilities in accordance with the goals of utility reform.
3. Identify the biggest challenges to adopting new responsibilities under the CoS model and existing regulations.
4. Given the new responsibilities, identify and prioritize which of the following six utility reform objectives are most important to the working group and key stakeholders:
    a. Align utility operations with climate policy objectives
    b. Support DER/energy efficiency implementation
    c. Remove utilities' incentive to grow energy sales
    d. Support Indigenous reconciliation
    e. Revise risk and value sharing
    f. Cost containment
5. Using the information presented in this research, identify which of the four reform options best satisfy the selected reform objectives.

	Reform objective	Utility reform option			
		PIMs	Revenue Decoupling	TOTEX	Platform Service Revenues
Reform Objective	Align utility operations with government climate policy objectives	✓✓✓	✓✓✓		✓✓
	Support distributed energy resource/energy efficiency implementation	✓✓✓	✓✓✓	✓✓	✓✓✓
	Remove utilities' incentive to grow energy sales so as to encourage energy efficiency projects	✓✓	✓✓✓		
	Support Indigenous reconciliation	✓✓✓		✓✓✓	✓✓✓
	Distribute risk and value sharing between utilities and third parties	✓✓	✓✓		✓✓
	Encourage cost containment			✓	
Pathway for Change	Change how rates are determined and/or structured		■		■
	New revenue opportunities	■		■	■

6. Revisit the main challenges in Step 3 to ensure that the selected reform options will address these challenges.
7. Map out what utility reform will look like in your jurisdiction. Determine which reform option to explore first. Study the impacts to rates and revenues, conduct pilot projects, and evaluate whether implementation of reform options should be done in one or multiple stages. Identify what actions are needed from governments, regulators, and utilities to implement utility reform.
8. Coordinate reform actions amongst working group members and stakeholders to ensure that utility reform has the necessary support and momentum to be

implemented and has the potential to solve the challenges identified at the start of the process.

Although ultimately provincial and territorial governments are responsible for the overall system change, utilities can also put forth measures and take initial steps to explore utility reform as it is utilities that are being asked to respond to new these emerging responsibilities.

Successful utility reform will require that utilities have the resources and internal capacity to implement changes to revenue, rates, and their overall operating structure. This, along with other facets of implementation, will very likely require funding support from governments such that utilities are able to explore, test, grow, and successfully adapt their practices with little financial risk before solutions are found.

8.3 Recommendations

The following list of recommendations are provided to governments, regulators, and utilities to understand the various levers and ways in which each main stakeholder can contribute, either by leading, or by supporting, utility reform. These recommendations are intended as a starting point for deeper collaboration, research, and policy change that could have meaningful system impact on electricity regulation in remote communities to support Indigenous-led clean energy progress.

8.3.1 Government recommendations to enable regulatory and utility business model reform

Utility reform in the remote community context can be supported through provincial, territorial, and federal government policies. The following recommendations enable and incentivize utilities to change the status quo and begin the exploration of utility reform motivated by government policy and action.

Provincial/territorial government actions

1. **Expand the mandates of regulatory bodies overseeing utilities so that regulators can ensure that the way utilities operate is aligned with reform objectives such as climate change, reconciliation, and customer choice.** Based on current mandates, regulators are predominately responsible for ensuring system reliability and reasonable rates for utility customers. This narrow mandate prevents regulators from supporting utility General Rate

Applications that incentivize meeting system performance standards (instituting performance-based regulations) which may increase the cost of electricity but meet objectives for reform. To address this, regulator mandates must evolve. Doing so will likely result in rate increases if utilities are operating under the Cost-of-Service model, which in turn would stimulate the exploration and evaluation of utility reform. Moving away from the Cost-of-Service model will require regulator mandates to reflect reform objectives such that regulators have a reason to take the steps necessary for utility reform.

Provincial and territorial governments must implement the necessary legislation and/or regulations to include decarbonization targets in utility and regulator mandates to align utility actions with achieving climate targets. Regulator oversight and direction is needed to ensure that utilities are supporting clean energy projects through the implementation of utility reform options, and this will require mandates to be updated to reflect this.

2. **Create guidelines and new policy tools for regulators to follow and use to ensure that utilities incorporate federal, provincial, and territorial climate and energy plans into their operating practices.** If mandates are extended, regulators will need more tools and increased support and guidance on how they should meet these new mandates. Creating a provincial/territorial "decarbonization standard" for utilities, similar to existing reliability standards that benchmark utility performance based on statistical indicators, would allow regulators greater flexibility to create regulations that incentivize utility decarbonization plans and help achieve provincial and territorial decarbonization or other climate goals.

3. **Prioritize Indigenous leadership in the clean energy transition through policy changes.** Ultimately, jurisdictions should affirm United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) into provincial and territorial law to be reflected by regulatory agencies. The adoption of UNDRIP is a key signal from provincial and territorial governments to regulators and crown corporations like utilities that action must be taken from their organizations to align practices with UNDRIP. This would also require that utility commission acts be amended to incorporate UNDRIP. This should be done with early and continuous Indigenous engagement and involvement to ensure that each jurisdiction's Indigenous peoples are fully aligned with proposed changes.

As an intermediate step, policies impacting utility actions and those that implicate third parties in the energy sector should be designed to prioritize Indigenous involvement in and ownership of projects to support the clean energy transition. This will require re-evaluating current policies to ensure that regulator and utility decision-making and actions reflect Indigenous rights and authority.

4. **Reform financial support systems for utilities.** Utility reform should ensure that government funding is appropriately targeted at supporting the business case and incentivizing the transition to renewable energy and energy efficiency. Current government diesel financing and subsidization of energy complicates utility reform implementation as government subsidies add an additional level of uncertainty to the effects each utility reform action will have on ratepayers.

   Any utility reform actions should still incorporate government support to mitigate consumer price impacts while shifting subsidies from diesel specifically to lowering energy costs more broadly. Government financing is still needed to make rates somewhat affordable for consumers; however, financing needs to be efficiently integrated with any new utility reform measures.

   Financing reform in itself may also be a subset of utility reform under the "rate design reform" umbrella, categorized in Table 6. Rather than applying subsidies directly to utilities, any continued financing or subsidization of diesel fuel should only interface with ratepayers directly through on-bill reimbursements. This avoids the cost impacts of high energy prices to ratepayers, while still ensuring that utilities account for the true cost of diesel in their resource planning, incentivizing the adoption of clean energy.

5. **Direct regulators to re-evaluate how utilities set consumer rates.** Utilities need the creative license to evaluate new and innovative methods of meeting their revenue requirements. If regulators do not provide utilities the flexibility to explore reform options or if regulators do not have clarity as to whether proposed rate design reform options are in line with their current mandates, governments may need to directly require regulators to support the examination of new rate structures and to approve utility proposals for alternate rate structures. This is a direct action government could take instead of changing legislation.

6. **Implement Renewable Portfolio Standards (RPS) and increase funding and programming for renewable energy projects.** Renewable Portfolio Standards

— which can be seen as a very top-down approach of supporting clean energy adoption — are a policy tool that requires utility to produce or procure a certain percentage of renewable energy, even if purchasing or generating diesel is cheaper. This will require utilities to re-evaluate their business models to adapt to these new costs. RPSs are also beneficial to utility reform as they establish some of the generation validation systems that are required to measure the effects of PIMs, if a renewable energy PIM is put into place. This will make implementing this PIM easier as the barrier concerning a lack of resources for tracking will already be addressed. RPSs are also beneficial to Revenue Decoupling as Decoupling alone does not incentivize an increase in renewable energy.

Increasing the penetration of renewable energy projects — especially non-utility owned renewable energy projects if the RPS specifies that renewable energy must be in part or in full procured rather than generated by the utility — will force utilities and regulators to re-evaluate opportunities for utility reform. To address concerns that RPSs are overly top-down, funding and programs should be increased to reflect RPS policy goals of increased renewable energy. Funding should be directed to non-utility entities such that utilities are still encouraged to explore options for utility reform. RPS policies with an emphasis on renewable energy procurement will create opportunities for Indigenous communities and entrepreneurs to fill these energy procurement needs. These positive impacts can be further driven by requirements of Indigenous ownership of and involvement in projects that qualify to meet RPS policies.

7. **Implement Energy Efficiency Resource Standards (EERS) and increase funding and programming for energy efficiency programs.** As with RPS policies, EERS are a policy tool that will also be a catalyst for reform options like Revenue Decoupling and PIMs. Long-term energy savings targets will force utilities and regulators to address the energy efficiency disincentive created by the CoS model and find other revenue opportunities. Like RPS policies, EERS will require increased funding to support the increase in energy efficiency projects.

8. **Increase funding to encourage utilities to explore different options to restructure their business practices.** Provincial or territorial government should support this work by commissioning and funding studies to evaluate each of these reform options and potentially identify other reform options that are suited to meeting each jurisdiction’s individual needs.

9. **Form a utility reform working group with entities from provincial/territorial and Indigenous governments, regulators, and utilities.** Implementing utility reform will require coordinated action from many parties. This will benefit from a working group where parties can collectively decide what their jurisdiction's priorities are, what emerging responsibilities need attention, and what steps should be taken to address these priorities and new responsibilities.

Federal government actions

10. **Increase funding to spur business model innovation and encourage utilities to explore different options to restructure their business practices.** Exploring utility reform options in the remote community context will require research, studies, pilot projects, and innovation sandboxes. Utilities, regulators, and provincial / territorial governments often do not have the operating budget and capacity to undertake these preliminary steps to explore reform options. The federal government should develop targeted programs aimed at supporting crown governments, Indigenous governments, regulators, and utilities interested in exploring reform options to encourage innovation.

11. **Establish a nation-wide government/utility collaborative process to support utility reform.** Although electricity governance is under the prevue of provincial and territorial governments, the federal government can still support reform by driving the conversation on a Canada-wide scale to start the process for utility reform in remote communities. This could be a federally driven research and engagement initiative to evaluate the feasibility of utility reform in remote communities with Indigenous engagement being a key component of this conversation.

8.3.2 Regulator recommendations to enable utility business model innovation

The following regulator changes and recommendations are needed to accommodate utility transformation. Many of the recommendations could potentially be initiated independently by the regulator without requiring government policy changes.

1. **Ensure early and active Indigenous participation in the regulatory process.** When regulators review utility rates and proposals for fairness, Indigenous viewpoints should be meaningfully incorporated into the review process beyond consultation. This could mean hiring Indigenous staff into decision-making

roles and/or reforming regulatory review processes to include local Indigenous governing authorities.

2. **Update rate structures and charges.** The CoS model disincentivizes energy efficiency initiatives and locks utilities into backward-facing, rather than innovative, billing structures. Implementing alternative rate structures allows for greater utility flexibility to adapt to changing technologies, usage patterns, and customer priorities. Regulators, as the entities who review and approve rates, need to allow utilities to alter their current methodology of establishing fixed and variable monthly charges. After regulatory mandates are updated to include reform objectives, regulators could also direct utilities to update their ratemaking methodology to align with the updated reform objectives. This recommendation is one that regulators could take independently of governments or could be a regulator action following recommendation #5 given to provincial/territorial governments in Section 8.3.1.
3. **Support the implementation of distributed energy resources (DERs) by updating renewable energy interconnection policies and increasing Independent Power Producer and net metering rates to accurately reflect the value of distributed energy resources.** To increase renewable energy penetration and increase opportunities for Platform Service Revenues, pricing structures and policies for ease of integration need to be adjusted so that financial and capacity barriers to project implementation are reduced or eliminated.

   As shown in New York's REV program, successfully integrating DERs necessitates using locally focused, complex pricing structures that account for the grid services that DERs provide. Current IPP and net metering policies may, depending on the jurisdiction, be undervalued in terms of the benefits they provide communities and energy systems. Updated regulations should require utilities to include a review and valuation of the ancillary services (e.g., reliability, flexibility, capacity) DERs provide to the electrical grid. Additionally, updated regulations should include standardized, simplified interconnection processes for DERs, as well as streamlined permit application processes and timelines. This will increase opportunities for platform service revenues by allowing for more DER-oriented services.
4. **Establish funding programs for pilot projects (often referred to as innovation sandboxes) to test the applicability of utility reform options for remote communities.** Across the board, utility reform options will require pilot project testing on a small scale to determine their feasibility for wider adoption.

This is of particular importance for remote communities as minor changes in reform option design can have large impacts due to the small customer base and the already high cost of living. Innovation sandboxes are regulator-driven programs that can allow utilities to interface with the regulator more closely as they test reform options. This also allows regulators to have a greater degree of insight into proposed changes and gives a direct signal to utilities that they are supportive of exploring alternative revenue generation and rate changes.

8.3.3 Utility actions to kickstart utility business model reform

Ultimately, implementing new business models requires policy and regulatory change. However, utilities can still take the following actions to start the process of utility reform.

1. **Using the perspective of both the utility and the customer, identify the objectives that reforms to the business model are intended to support. Based on those objectives, determine which reform options to implement.** Utilities must engage with customers to identify priorities for utility reform and have discussions internally on what the utilities' own priorities are. Each jurisdiction will have unique objectives for utility reform. Objectives will be informed not only by policy but also by customer and utility priorities, whether for increased economic opportunities, sustainability, or expanded energy offerings, among others. Utilities should engage with customers to establish the groundwork for what utility reform options are best suited to meeting customer objectives.

   Once these priorities are set, utilities can then begin identifying and evaluating reform options, leveraging programs that may have already been established such as federal funding streams or regulator innovation sandboxes.
2. **Commit to Indigenous reconciliation and partnership.** Energy sector participation is a major opportunity for Indigenous communities to unlock economic and asset ownership benefits. To do this, utilities must recognize the barriers they and their business models currently pose to accessing these benefits. Meeting the utility reform objective of supporting Indigenous reconciliation will require utilities to fully commit to reconciliation and forming strong and long-lasting partnerships with the communities they operate within. This commitment can be utility driven, beyond government requirements to recognition or changes to current regulations. As the clean energy transition progresses, utility-community partnerships will be key to success, particularly for remote communities.

3. **Assess the feasibility of new utility business models and propose these new business models to regulators.** Utility proposals that go beyond the bounds of General Rate Applications and the Cost-of-Service model are a concrete method to trigger the utility reform process. Utilities also have better insight regarding the effects of these changes to their revenue and rates; hence, reform options that require nuanced design decisions may be better if crafted by the utility. Innovative proposals from utilities can spur regulatory review and build momentum towards making change.

8.4 Conclusions

If climate and energy policy objectives regarding a decarbonized grid and equitable energy systems that prioritize Indigenous involvement are to be realized, utility reform is necessary — but is part of a bigger picture of actions to progress the clean energy transition, as shown in Figure 19.

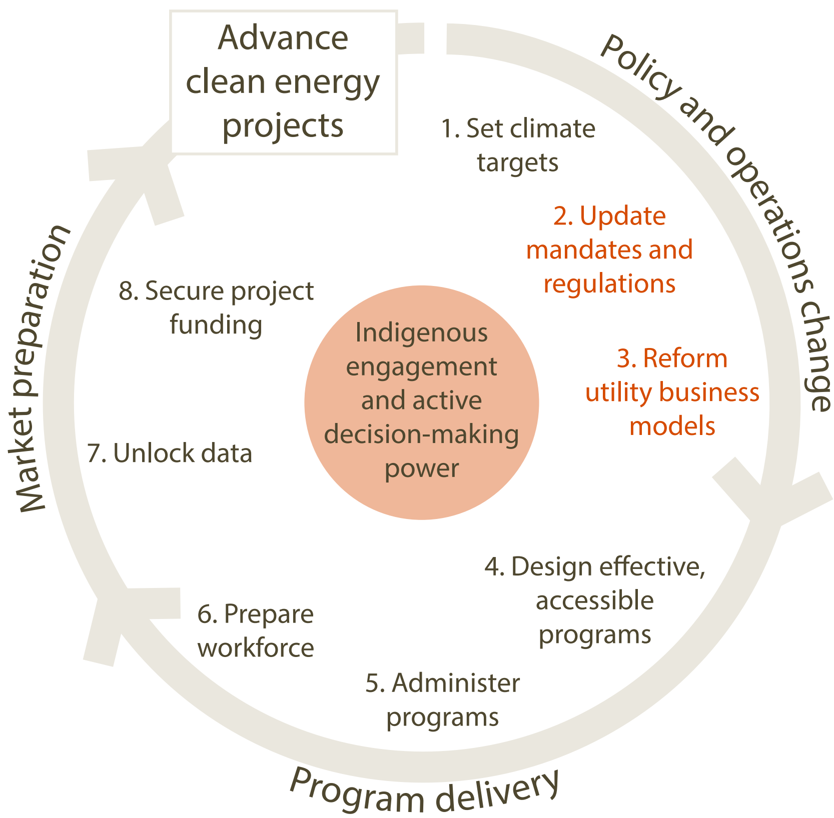


Figure 19. Clean energy transition roadmap
Adapted from: American Council for an Energy-Efficient Economy[81]

[81] Mike Specian, Rachel Gold, and Jasmine Mah, *A Roadmap for Climate-Forward Efficiency* (American Council for an Energy-Efficient Economy, 2022), 9. https://www.aceee.org/sites/default/files/pdfs/u2202.pdf

Utility reform creates new pathways for utilities to satisfy existing and emerging policy and customer priorities not currently addressed under the CoS model through rate design reform and new revenue opportunities. For utilities to no longer be barriers towards clean energy project progress, utility reform is needed such that utilities can monetize the value of implementing energy efficiency and facilitating customer-owned generation. To do this, regulation must change to accommodate innovative ways for utilities to collect revenue that do not hinder the clean energy transition while still accounting for the unique challenges faced by utilities serving remote communities, encouraging community and Indigenous-led renewable energy projects, while still ensuring financial sustainability for the utility.

Utility reform should be sensitive to the regulatory process, recognizing that regulatory change is often incremental and the relationship between governments and regulators is complicated. Allowing utilities to propose and adjust rate and revenue designs over several rate cases and regulatory proceedings, such that there is time for public engagement and review of proposed changes, is important. Ratepayers are critical stakeholders in this process, as these changes may have direct and noticeable impacts on their electricity bills and utility interactions. This is especially significant when considering the remote community context and the fact electricity rates are already high. The high penetration of public housing in remote communities means that utility reform will also have impact on provincial / territorial government budgets if rates change. Feedback should be sought throughout the utility reform process to ensure ratepayers support the transition and are aware of the driving forces, new responsibilities utilities are responding to, and the benefits that could come from utility reform.

Utility reform must occur at all levels of utility governance, as shown in Figure 20. Action often needs to come from provincial and territorial governments within the agencies that dictate climate action and define utility regulations, but it doesn’t necessarily have to start there — regulators and utilities can take independent actions to progress utility reform. Government must ensure that policies and targets are translated into utility planning and that there is greater consistency between government, regulator, and utility action. Governments need to implement effective policies, programs, and regulations to increase energy efficiency and renewable energy projects in conjunction with directly supporting projects that are championed by Indigenous communities.

This change, and direction from government, will then require action from the regulators that oversee utility General Rate Applications and from utilities themselves.

Utility reform should incorporate distinct Indigenous engagement, involvement, and decision-making throughout to ensure that future policy, regulatory, and utility frameworks servicing remote communities are aligned with the needs and priorities of impacted Indigenous peoples and that utility reform respects and responds to Indigenous rights.

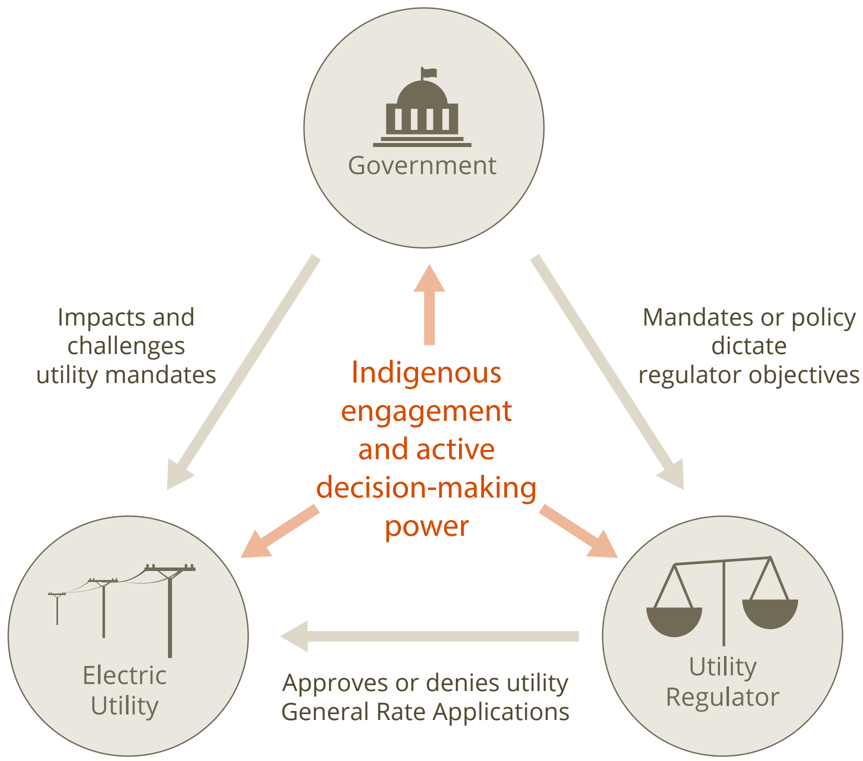


Figure 20. Indigenous involvement and the government-regulator-utility trifecta

Mitigating rate impacts will be very important for utility reform in remote communities and this will require careful consideration to balance utility priorities with reform objectives and the impact on rates. Energy costs in remote communities are already subsidized, with a portion of the costs covered by government programs. This could be an advantage to utility reform in that governments already have experience and systems in place for collecting and subsidizing energy for ratepayers by working closely with utilities, as it is expected that there will be a continued reliance on government subsidies in the early stages to support reform.

Utility reform is complex and must be tailored to each jurisdiction's current operations. It should be stressed that seemingly small changes can have large impacts on the overall success of reform implementation. The reform options presented in this study are not meant to provide prescriptive recommendations to any jurisdiction, as individual communities and utilities will need to tailor these options to fit their unique contexts. Future studies on rate impacts and pilot projects will be required to ensure the validity and effectiveness of the proposed utility reform measures. To avoid the potential repercussions of utility resistance to customer-driven revenue impacts due to energy efficiency and renewable energy projects, utilities servicing remote communities should be proactive in supporting an inclusive transition to clean energy that respects Indigenous and community rights while protecting customer interests into the future.

Establishing a utility reform working group — either specific to a jurisdiction, or nationally, as identified in some of the recommendations in this report — will be critical to the success of utility reform in remote communities. Utility reform will require a multi-stakeholder effort consisting of utilities experiencing similar challenges, Indigenous stakeholders who want to see this change happen, and governments that have the ability to update policies and regulations.

Appendix A. Legislation establishing regulator mandates and responsibilities

Table 13. Regulator responsibilities, mandates, and key legislation

Regulator	Core Responsibilities and Mandates	Key Governing Legislation and Purpose	Supporting Legislation and Regulations
Alberta Utilities Commission (AUC)	Regulate "the utilities sector, natural gas and electricity markets to protect social, economic and environmental interests of Alberta where competitive market forces do not" Provide market oversight and enforcement Determine the need for construction, alteration, and decommissioning of electric transmission facilities Make decisions on the construction, alteration, and decommissioning of electric generation facilities Regulate utilities to ensure reliability and safety at just and reasonable rates	Electric Utilities Act (2003) – Primary electricity sector governing legislation Hydro and Electric Energy Act (2000) – Ensures generation, transmission, and distribution are built economically, efficiently, and safely Alberta Utilities Commission Act (2007) – Establishes the AUC	Renewable Electricity Act (2016) – Establishes Alberta's 30% renewable energy by 2030 target Micro-generation Regulation (amended 2016) – Establishes rules for interconnection of non-utility-scale generating technologies
British Columbia Utilities Commission (BCUC)	"Ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the utilities it regulates, and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital"	Utilities Commission Act (1996) – Primary electricity sector governing legislation	Clean Energy Act (2010) – Sets GHG reduction targets and provincial electricity self-sufficiency goals BC Hydro Public Power Legacy and Heritage Contract Act (2003) – Establishes responsibility to "generate, manufacture,

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	Facilitate fair, transparent, and inclusive processes that encourage well-represented input from relevant stakeholders Lead by making objective and well-reasoned decisions and treating stakeholders with dignity and respect Deliver efficient regulation, aligned with all relevant legislation, regulations, and government policies that considers utility business needs and the public interest Develop new efficiencies and innovative solutions in international operations and regulatory processes	Hydro and Power Authority Act (1996) – Outlines the framework governing BC Hydro	conserve, supply, acquire, and dispose of power and related products" First Nations Clean Energy Business Fund (created through the Clean Energy Act) – Promotes increased Indigenous participation in the clean energy sector and provides revenue sharing agreements Declaration on the Rights of Indigenous People Act (2019) – Requires government to update laws and policies to reflect Indigenous rights and title
Manitoba Public Utilities Board (PUB)	Regulate electric and other utilities Establish rates for service and provision of electrical power by Manitoba Hydro	Manitoba Hydro Act (1949) – Establishes Manitoba Hydro powers Crown Corporations Governance and Accountability Act (2017) – Requires Manitoba Hydro to submit rate changes to the PUB and prepare annual business plans that include CAPEX	Efficiency Manitoba Act (2017) – Establishes responsibilities for meeting energy savings targets, mitigating rate impacts of rate increases, encouraging innovation Public Utilities Board Act (2007) – Exempts Manitoba Hydro from PUB provisions except rates hearings
Newfoundland and Labrador Board of Commissioners of Public Utilities (NL PUB)	Ensure just and reasonable rates to maintain reliability and safety of electrical services Regulate utility capital expenditures and rates Ensure safe and reliable electricity services Ensure adequate electrical system planning	Public Utilities Act (1989) – Defines NL PUB responsibilities Electrical Power Control Act (1994) – Gives NL PUB regulatory oversight over NL Hydro, including setting rates Hydro Corporation Act (2007) – Further defines NL Hydro roles and responsibilities	Public Utilities Acquisition of Lands Act (2004) – Public utilities may acquire lands where necessary for construction or operation of a transmission line

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Northwest Territories Public Utilities Board (NT PUB)	Ensure just and reasonable rates from regulated utilities Ensure provision of safe, adequate, and secure services	Public Utilities Act (1988) – Establishes NT PUB and provides authority to approve rates	Northwest Territories Power Corporation Act (1988) – Establishes NTPC as responsible for transmission and most generation and distribution (non-governmental utilities may purchase wholesale power from NTPC and sell to customers in its distribution area), Requires NTPC "undertake programs to conserve energy" and "ensure a continuous supply of energy adequate for the needs and future development of the Territories"
Nunavut Utility Rates Review Council (URRC)	Advise the Minister on QEC permit applications for major capital projects over $5M Advise the Minister on QEC revenue requirement and capital costs to ensure fair return to shareholder (Government of Nunavut) Advise the Minister on rates, tariffs, and rate structure for electricity generation, transmission, and distribution	Utility Rates Review Council Act (2001) – establishes URRC as advisory body for QEC Qulliq Energy Corporation Act (1988) – Establishes QEC as sole generator and distributor of electricity in Nunavut	An Act to Amend the Qulliq Energy Corporation Act (2018) – Allows IPPs to sell power to QEC under a PPA, retains QEC as solely authorized retail energy supplier Nunavummi Nangminiqaqtunik Ikajuuti (2017) – Sets Inuit labour level commitments and training requirements to increase Inuit Firm participation in business opportunities and improve capacity to compete for contracts
Ontario Energy Board (OEB)	"[Support] and [guide] the continuing evolution of the Ontario energy sector by promoting outcomes and innovation that deliver value for all Ontario energy consumers" Establish reasonable rates and prices that allow utilities to invest in the system Encourage higher utility performance and measure progress	Electricity Act (1998) – Outlines the framework for the competitive electricity marketplace Ontario Energy Board Act (1998) – Outlines the OEB mandate	Green Energy and Green Economy Act (2009) – Promotes conservation and renewable energy development Strengthening Consumer Protection and Electricity System Oversight Act (2015) – Increases OEB powers to enhance consumer protection, Allows utilities to expand business activities Fair Hydro Plan Act (2017) – Establishes a framework to distribute costs and benefits

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	Make energy issues and consumer usage easier to understand Investigate complaints and apply penalties where appropriate in the consumer interest Develop regulatory policies to meet emerging and long-term challenges		of the "clean energy initiative" among current and future customers Energy Statute Law Amendment Act (2016) – Expands OEB objectives to include facilitating implementation of long-term energy plans
Régie de l'énergie (the Régie)	Establish, monitor, and enforce regulations for electricity transmission and distribution Establish reasonable rates and prices that allow utilities to invest in the system Monitor transmission and distribution conditions Investigate complaints, apply penalties where appropriate, and promote satisfaction of consumer needs Authorize construction, acquisition, and sale of transmission and distribution assets Monitor petroleum product prices Assess long-term energy sector needs and approve Transition énergétique Québec programs	Act respecting the Régie de l'énergie (1996) – Outlines the framework for Québec's regulated and competitive electricity marketplaces Hydro-Québec Act (1996) – Outlines Hydro-Québec roles and responsibilities, establishes that IPP generators can fulfill utility generation requirements where necessary	2030 Energy Policy (2016) – Sets target for 25% more renewable energy and 50% more biomass, requires Hydro-Québec to develop plans for converting remote community diesel generation to clean power systems, supports "projects of off-grid communities… to convert electricity generation using fossil fuels to renewable energy sources" Plan Nunavik (2010) – Outlines goals to build renewable energy projects in the short term and connect all remote communities to the integrated grid in the long term
Saskatchewan Rate Review Panel (SRRP)	Monitor rate requests Provide a report of observations on electricity rates to the Minister of Crown Investments Corporation	Crown Corporations Act (1993) – Establishes the Crown Investments Corporation as managing entity for SaskPower Power Corporation Act (1979) – Grants SaskPower exclusive rights to supply,	

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	Hire independent experts to assess application of rate reviews and provide SRRP with technical advice Invite public comments on rate reviews Conduct public consultation to provide information on rates and release documents to the public	transmit, and distribute electricity in the province	
Yukon Utilities Board (YUB)	Issue orders fixing public utility rates for YEC and ATCO Electric Yukon Prohibit or limit proposed rate changes Fix standards and regulations to be followed by the public utilities Determine service areas of the public utilities	Public Utilities Act (2002) – Provides the regulatory framework under which the YUB regulates public utilities Yukon Development Corporation Act (2002) – Establishes the Yukon Development Corporation, parent company of YEC, Yukon's main electricity generator and transmitter	Our Clean Future (2020) – Sets targets for ensuring reliable, affordable, and renewable energy (97% renewable by 2030 overall, on-grid: 93% renewable, off-grid: reduce diesel by 30% from 2010 levels) Yukon's Independent Power Production Policy (2018) – Enables third parties to generate additional power (up to 10% of electricity demand) to help fulfill clean energy goals, aspirational target of at least 50% of IPP projects to have a Yukon First Nation ownership component