AUC
Alberta Utilities Commission

Rule 024 engagement questionnaire

Comments from (*company/stakeholder name*):	Cogeneration Canada Ltd. (CCL) Manufacturer / Integrator	**Contact name (*for companies*):**	Thiago Avila, P.Eng., CFA (Director)
Date [yyyy/mm/dd]:	2026/09/08	**Phone:**	[redacted]
Role:	Microgeneration proponent / developer & manufacturer (small <150 kW natural-gas mCHP)	**Email**:	[redacted]

Instructions

1. Please download this document, save as "**Rule 024 questionnaire**" and fill out the demographic/contact information above.

2. Please review Bulletin 2026-10.

3. In the box above, please provide your name, your organization's name (if applicable), and the role(s) that best describe(s) your participation in the microgeneration field (customer, consultant, developer, distribution facility owner, transmission facility owner, government agency, non-governmental organization, microgeneration proponent, etc.).

4. Some of the questions included in this engagement apply only to specific roles (such as microgeneration customer/proponent, distribution facility owner, etc.). Please only answer questions relevant to your self-identified role(s) and/or experience. You do not need to complete every question to participate in this engagement. Incomplete questionnaires will be accepted.

5. Where you provide any recommendations, please include reasons or justifications.

6. Submit your response to engage@auc.ab.ca. In the email, please include the following subject line: **Rule 024 engagement**.

Questions

Timelines

1. Please briefly describe your experience with the timelines to connect microgeneration generating units. Where applicable, please explain any differences between the connection for small (<150 kW) and large (150 kW – 5 MW) microgeneration generating units.

CCL designs, manufactures, owns, and operates natural-gas-fired micro combined heat and power (mCHP) units in the 20–150 kW electrical range for customers with significant useful thermal demand and material electrical demand, including greenhouses and other agricultural operations, process manufacturers, recreation centres, warehouses, and multi-tenant commercial buildings. In most cases, the unit replaces a gas-fired boiler serving a hydronic system. All our projects qualify as small (<150 kW) microgeneration under the Micro-generation Regulation; we have no direct experience with larger (150 kW–5 MW) grid-connected units in Alberta.

Our experience is that the 14-day acceptance window in Rule 024 s.3(3) is not the binding constraint for mCHP. The binding constraint is the qualification step under Regulation s.1(1)(h)(ii) ("intended to meet all or a portion of the customer's total annual energy consumption"), which the distribution facility owner (DFO) administers as an electricity-only test. An mCHP unit is heating plant that co-produces electricity; its correct size is set by the site's useful thermal demand, not by its electrical consumption. Because Rule 024, Form A and the Guideline contain no field, method or standard for thermal demand, our units have been assessed on electrical nameplate alone (at 100% of nameplate for 8,760 h/yr), and the resulting request to downsize (or to leave the microgeneration stream altogether) has been the dominant driver of elapsed time, re-engineering and cancellation on our projects.

Two features of mCHP make this worse than it would be for PV. First, an mCHP unit is bound by discrete frame, alternator and engine sizes; it cannot be built to an arbitrary calculated nameplate, and it cannot be expanded later to meet the heating demand it was intended to serve, so an undersized unit permanently prevents the replacement of the customer's boiler. Second, each serial-production unit is subject to the DFO's witnessed Interconnection Protection Settings and Commissioning (IPSC) test at every site, which adds cost and schedule that a certified PV inverter does not carry.

The practical result is that the timeline for a PV unit of a given nameplate and the timeline for an mCHP unit of the same nameplate at the same site are not comparable, even though both are "small" microgeneration under the same Regulation and the same Rule.

2. Have you observed or experienced delays in the microgeneration connection process? If yes, please explain the main contributing factors.

Yes. In order of contribution:

1. Sizing methodology (dominant). The DFO's electricity-only, 8,760 h/yr nameplate test is not stated in the Regulation, Rule 024, Form A or the Micro-generation Notice Submission Guideline; it is an internal DFO practice. Because it is unpublished, the proponent discovers it only after the notice is filed, and the exchange that follows (request for justification, request to downsize, discussion of the alternative Small Scale Generation stream) restarts the engineering and commercial work. Each iteration has added months to the schedule. Sizing a CHP unit on electricity alone, which is not the market CHP serves, while assuming 100% load and capacity factor on an annualised basis, is not a reasonable test; our answer to Question 3 below sets out why.

2. Technology-class routing. Form A recognises synchronous generators and combined heat and power by name, but its only technical-compliance questions are inverter-specific (CSA C22.2 No. 107.1, UL 1741 Supplement B), and the Guideline and most DFO terms and conditions are likewise written around inverter-connected units. Synchronous units – single-phase under DER-01 and three-phase under DER-02 in FortisAlberta's case – are

routed to the DFO's distributed-generation technical group for protection review and a site-witnessed IPSC test, with timelines and information requests more typical of a larger, one-off distribution-connected generator than of a <150 kW microgeneration unit in serial production.

3. Absence of a defined decision path. When the DFO disagrees with the proposed size, the matter has been handled by correspondence and informal requests to resize, rather than by a Form B notice of dispute within the 14 days contemplated by Rule 024 s.4(1)–(2). A formal dispute would at least produce a Commission determination on the sizing question and a decision on the record; informal resizing produces neither, and leaves every subsequent mCHP applicant to re-argue the same point.

a. If yes, is there more information that distribution facility owners could provide before the start of a microgeneration project to help reduce delays? Please comment on each of the suggestions below:

Yes. Comments on each suggestion follow.

i. General information about phases of the connection process and associated minimum timelines.

Helpful and low-cost. Each DFO should publish, per size category and per generator technology class (inverter-based vs. synchronous/rotating machine), the phases of the connection process, the minimum and typical elapsed time for each phase, and the deliverable that closes each phase. This should be a standard-format table rather than narrative, so that proponents can compare DFOs and so the Commission can see where elapsed time is actually accumulating.

ii. Comparison between connection timelines, phases, and other requirements for small and large microgeneration projects.

Helpful, but the more important comparison for our segment is not small vs. large; it is inverter-based vs. synchronous generation within the small category. The only equipment term Rule 024 defines is "inverter" (s.1(d)). Form A lists "combined heat and power" as an energy source and "synchronous" as a generator type, but its only technical-compliance questions are inverter-specific; it has no equivalent field for a synchronous unit's controller certification, protection functions or test report, and no field for thermal demand or output. A synchronous mCHP unit at 40 kW is administratively treated more like a distribution-connected generator than like a 40 kW PV array. The comparison table should therefore include a technology-class dimension, and should state explicitly which additional studies, commissioning tests (in particular the witnessed IPSC test) and timelines the DFO applies to synchronous units below 150 kW.

iii. An explanation of common circumstances that may lead to delays in the connection process or restarts of phases (including delays in customer/microgeneration proponent responses to owners' questions).

Strongly supported, with one specific addition. Each DFO should publish the methodology it uses to determine whether a proposed unit is "intended to meet all or a portion of the customer's total annual energy consumption." At a minimum the published methodology should state: the production estimate applied to each technology class (expected annual yield for PV; capacity factor or nameplate × 8,760 h for dispatchable units); the consumption data accepted (number of historical years, treatment of planned load additions); whether and how the site's thermal demand is considered for a CHP unit; and the evidence of intent the DFO will accept (declared operating modes and control, export limiting).

For mCHP, the absence of a published methodology is the single largest cause of restarted applications and of cancelled projects, including projects with well-qualified customers. It is entirely avoidable if the test is written down before the notice is filed. The methodology must account for the customer's thermal load; a CHP unit's output has to follow the site's thermal demand in near real time, and a sizing test that disregards that load forecloses the replacement of the customer's heating equipment, which is the purpose of installing the unit. Our answer to Question 3 below sets this out in full.

iv. Other (please explain).

Two further items: (i) a technology-specific checklist of the protection, control and commissioning-test requirements the DFO applies to synchronous and inverter-based units under 150 kW, including whether a type-test report for the unit model is accepted in lieu of a site-witnessed IPSC test (see Technical standards below), and (ii) an indication, at or before Form A acceptance, of whether the DFO anticipates that any connection cost may be treated as extraordinary under Regulation s.4(3), with a preliminary range. Both would allow a proponent to settle on a design and a stream before committing engineering spend.

b. If yes, is there more information that customers or microgeneration proponents could provide in their initial microgeneration applications to help reduce delays? Please comment on each of the suggestions below:

Yes, provided the information requirements are published in advance and are the same for every applicant in a given technology class.

i. More accurate or detailed information about the technical specifications of their microgeneration project.

Supported. For a CHP unit, the notice should capture the information that actually determines the unit's size and operating behaviour:

(i) The site's peak useful thermal demand (kWth) and the basis for it: an engineering assessment of the existing heating plant's duty (installed boiler capacity, firing records, process heat balance), reconciled to historical gas consumption.

(ii) The site's annual thermal consumption (GJ), taken from 12 to 36 months of gas bills.

(iii) The unit's thermal output (kWth), electrical output (kWe) and heat-to-power ratio.

(iv) The unit's operating modes (heat-led when thermal demand is present; electricity-led when that service is required) and the control system that enforces them.

(v) Any export limit.

(vi) The heating equipment the unit will replace, and any auxiliary heat source to be retained.

Items (i) to (iii) are already implicit in the 418 kg CO_2e/MWh eligibility test in s.1(1)(l)(ii)(B) of the Regulation, which is assessed on the total electric and thermal energy produced by a CHP unit. Because this information is already required to establish eligibility, it should be captured in the same form and used for sizing. No thermal metering is proposed or required: the thermal basis is established once, at application, from gas bills and engineering assessment, and electrical output is already recorded by the interval meter installed for every unit.

ii. Justification for the proposed microgeneration project's size with reference to the customer's annual energy consumption and evidence of any planned future upgrades.

Supported in principle, provided the justification is measured against the right quantity. For a CHP unit, annual electrical consumption is the wrong sizing basis, and so is annual-average thermal load.

The reason is physical. Whatever the thermal use – process heat, space heat, water heating, drying or any other useful purpose – heat cannot be stored in any material quantity and must be produced at the time and at the rate it is needed. Heating plant is therefore sized to peak useful thermal demand. A unit that cannot meet the demand when it occurs requires an auxiliary gas-fired or electric heat source, and the existing boiler(s) cannot be retired. Electricity has the opposite property: surplus can be exported to the grid and re-imported later, which is precisely the mechanism the Regulation already provides in s.7. Because the two load types at a site are not synchronised through the year, no single electrical constraint can be applied to a CHP unit without making it either too small to serve the heat load or unable to qualify. Sizing is also a one-time decision, fixed at installation, representing a large capital outlay that cannot be resized without replacement; a test that disregards thermal load permanently forecloses the displacement of the customer's heating equipment. A full-load, 8,760-hour electricity-only assumption is neither practical nor defensible as a requirement (see Question 3).

CCL recommends that Rule 024 or the Guideline set out an accepted sizing method for CHP:

(i) The unit's thermal output may not exceed the site's peak useful thermal demand, established by an engineering assessment of the existing heating plant and process, reconciled to 12 to 36 months of historical gas consumption.

(ii) The electrical nameplate follows from the unit's heat-to-power ratio.

(iii) The operating modes (heat-led when thermal demand is present; electricity-led when that service is required) and the control system that enforces them are documented in the notice.

(iv) The thermal basis is established once, at application; no thermal metering is required.

On planned future upgrades: evidence of planned load additions should be accepted on the same basis for CHP as the Commission has already accepted for PV (Decision 23412-D01-2018), and should extend to planned thermal load additions as well as electrical, documented by the same engineering assessment used to establish peak useful thermal demand.

For dispatchable units other than CHP, and as an interim measure for CHP until the Regulation is amended, the production term should be the unit's expected annual output under its declared operating mode – the same expected-yield principle already applied to PV – and not nameplate × 8,760 h.

iii. Other (please explain).

Nothing further, except to note that requests for additional information should be made once, in writing, against a published list. Serial requests are the main way that a 14-day process becomes a multi-month process.

3. In your experience, how often are delays linked to the *Micro-generation Regulation*'s restriction of maximum microgeneration generating unit size to "all or a portion of a customer's total annual energy consumption"? Please explain.

For mCHP: almost always. Every mCHP notice CCL has filed to date has been challenged on this ground. The restriction, as written and as administered, is the single reason mCHP is not deployable at scale in Alberta, and CCL's principal request in this engagement is that Rule 024 adopt a thermal-demand sizing standard for CHP.

What the challenge has looked like in practice. CCL has been required to provide signed and sealed professional engineering assessments to justify unit size, which we have done, and the DFO has nonetheless sought to impose electrical nameplates derived from its own electricity-only, 8,760-hour calculation. The sizes proposed by the DFO frequently do not correspond to any unit manufactured by CCL or by anyone else in the market: packaged mCHP is produced in discrete sizes, and a calculated figure such as 14 kWe cannot simply be ordered. Where an available unit is instead derated by its controls to the DFO's figure, it runs at a turndown that reduces electrical efficiency, prevents it from meeting the site's thermal requirement, increases specific maintenance cost, and spreads the fixed cost of interconnection, controls and installation over a fraction of the output. In either case the result is a unit that is uneconomic for the customer, cannot displace the existing heating equipment and does not do the job it is installed for, and the project is cancelled.

Why thermal demand governs. An mCHP unit is heating plant first: its purpose is to replace the customer's existing gas-fired boiler (in most of our cases a boiler serving a hydronic system) and to co-produce electricity from the same fuel. The thermal use may be process heat, space heat, water heating or any other useful purpose; the physics is the same in each case. Heat cannot be stored in any material quantity. It must be produced at the time and at the rate it is needed, or it is wasted; if the unit cannot produce it when needed, an auxiliary gas-fired or electric heat source must be kept, and the boiler is not retired. Electricity has the opposite property: surplus can be exported to the interconnected electric system and re-imported later, which is exactly the mechanism the Regulation already provides in s.7. The two demands at a site are not synchronised through the year. It follows that the unit must be sized to peak useful thermal demand, must run heat-led whenever thermal demand is present and electricity-led when that service is required, and that the electrical balance must be allowed to settle over the year through the grid. Sizing is a one-time decision, fixed at installation; a test that disregards thermal load does not merely reduce the unit size, it permanently forecloses the displacement of the customer's heating equipment, which is the purpose of installing it. Retiring the boiler(s) and other heating equipment is not incidental to CCL's business; without it there is no economic case and no target market. A CHP unit's availability is comparable to that of the boiler it replaces; a site's backup heating arrangement is the same after the CHP is installed as before, so the replacement does not introduce a new outage risk.

Why the 8,760-hour test is unreasonable. Sizing a CHP unit on electrical consumption alone, and assuming 100% load at full nameplate capacity for all 8,760 hours of the year, is not a defensible test. Electricity-only sites are a poor fit for CHP and are not the market it serves: with none of the recovered heat used, the unit would fail the emissions test in s.1(1)(l)(ii)(B), and such a site is better served by another technology. No CHP unit operates at full load continuously; its output follows the site's thermal demand. A full-load, 8,760-hour assumption is neither practical nor defensible as a requirement, and it disqualifies precisely the projects the micro-generation program is intended to enable.

Why the Regulation's own eligibility test points the same way. Section 1(1)(l)(ii)(B) qualifies CHP only if the greenhouse gas intensity of the total electric plus thermal energy produced is at or below 418 kg CO_2e/MWh. Natural gas at roughly 180 kg CO_2e/MWh of fuel gives about 545 kg/MWh on an electricity-only basis (electrical efficiency ≈ 33%), which fails; the unit passes only when its recovered heat is actually used (about 205 kg/MWh at 88% total efficiency). The eligibility test therefore already assumes that the unit is sized and operated to a real thermal load. A site whose demand is predominantly electrical cannot use the heat, cannot meet 418 kg/MWh, and should not qualify; CCL accepts that. Our target customers are heat-dominant sites with a material electrical demand, and for them the Regulation's eligibility test and its sizing test currently point in opposite directions.

Illustration (representative process or institutional site – food processing, commercial laundry, dairy, or a recreation centre with a pool – with a gas-fired hydronic boiler): electrical consumption 450 MWh/yr; gas consumption 4,000 GJ/yr from gas bills, which at an 82% seasonal boiler efficiency is 911 MWhth of useful heat; the load runs about 20 hours a day, six days a week, so with a buffer tank the thermal load factor is about 0.75 and the peak useful thermal demand from engineering assessment is about 140 kWth against an annual average of 104 kWth. A unit sized to that demand is 80 kWe / 136 kWth (33% electrical and 56% thermal efficiency, heat-to-power ratio ≈ 1.7). It runs about 6,700 hours a year at rated output (capacity factor 0.77), meets the site's heat in essentially every operating hour, and retires the boiler. It produces about 537 MWhe against 450 MWh consumed: a net export of 87 MWh,

16% of output, settled under s.7. The DFO's method instead assumes 80 kWe × 8,760 h = 701 MWh – 30% more than the unit can physically produce while following the heat load – and on that basis caps the unit at 51 kWe. The nearest manufactured unit, 50 kWe / 85 kWth, covers about 78% of annual heat, cannot meet demand in most operating hours, and leaves the boiler in service. For the sites CHP is well suited for a thermal peak-demand standard is not a licence to oversize.

Consider the same heat load and the same 80 kWe unit at a site whose electrical consumption is 600 MWh/yr instead of 450. The unit's output does not change: following the heat load, it still produces about 537 MWhe. That is now 89% of the site's consumption, so the unit is a net importer over the year and would pass any test based on what it actually produces. It fails the DFO's test anyway, because the DFO does not use actual production: it multiplies nameplate by 8,760 hours (701 MWh), compares that figure with the 600 MWh consumed, and rejects the unit for exceeding a level of output it cannot physically reach while serving the heat load. In this case the 8,760-hour assumption is the sole reason the project fails. For a greenhouse, where useful heat is typically 2-5 times electrical consumption, no electricity-based method produces a usable unit.

What CCL asks the Commission to do. (1) Adopt in Rule 024, Form A and the Guideline a CHP sizing standard in which the unit's thermal output may not exceed the site's peak useful thermal demand, established by engineering assessment reconciled to 12–36 months of historical gas consumption; electrical nameplate follows from the unit's heat-to-power ratio; and the operating modes and control are documented in the notice. This is a cap, not a requirement: a proponent may size below it and may retain an auxiliary heat source. A signed and sealed engineering assessment against this standard should be accepted as conclusive of size unless the DFO issues a Form B notice of dispute with reasons. (2) Recognise that s.1(1)(l)(ii)(B) already defines a CHP unit's output on a total-energy basis for eligibility, and that the same basis should govern sizing; the Commission's reasoning in Decision 27017-D01-2022 (NuVista) – that generation "reasonably scaled to meet the electricity and thermal needs" of a site is reasonable, and that it is "impractical to precisely scale on-site generation for a specific thermal or electrical output" – is directly applicable. (3) Address the legal path. CCL obtained an independent legal opinion (McLennan Ross LLP, March 2026) which concludes that "total annual energy consumption" in s.1(1)(h)(ii), read in its statutory context, means electrical consumption only, and that a targeted amendment to s.1(1)(h) and s.1(1)(h)(ii), with a definition of "useful thermal energy", is required for thermal demand to govern sizing. CCL has raised that amendment with Alberta Affordability and Utilities. We therefore ask the Commission to (a) communicate to the Minister that the sizing mechanism does not accommodate a technology the Regulation expressly recognises and that the Commission supports the targeted amendment; (b) draft the Rule 024, Form A and Guideline provisions for the thermal-demand standard now so that they take effect with the amendment; and (c) in the interim, direct that the production term for dispatchable units be expected annual output under the declared operating mode rather than nameplate × 8,760 h, which the Commission can do within its existing interpretive latitude (Decisions 23412-D01-2018 and 28319-D01-2023) and which removes part, though not all, of the problem.

4. **[Customers/microgeneration proponents only]** Are you generally aware of each of the following? For each ‘no’, please suggest how the information could be provided more accessibly.

Yes to all three, with the qualifications below.

a. Legislative requirements applying to microgeneration in Alberta.

Yes. The gap is not awareness of the Regulation; it is the absence of any published statement of how the DFO applies s.1(1)(h)(ii) to a dispatchable unit. The Micro-generation Notice Submission Guideline instructs the applicant to "calculate or estimate how much alternating current electric energy can be generated from the generating unit per year", which is an expected-production instruction, and does not state that a DFO may substitute nameplate × 8,760 h. A short Commission-issued interpretive note or Guideline revision on this point would remove most of the ambiguity.

b. Differences between microgeneration, small scale generation, and distribution-connected generation.

Yes. CCL understands the three streams and has evaluated them for our customer segment (see the Small Scale Generation Regulation questions below). The information could be made more accessible by a single Commission-hosted comparison table showing, for each stream, the eligibility test, the compensation mechanism, the interconnection cost responsibility, the study fees, and the typical timeline; and by stating expressly which stream is intended for demand-matched, behind-the-meter generation that is not solar.

c. The terms and conditions of service that apply to microgeneration generating units in each distribution facility owner's service area.

Yes, they are available, and the difficulty is not disclosure. The technical requirements applied to CCL's units are published. CCL's single-phase unit was processed by FortisAlberta under DER-01 (Technical Interconnection Requirements for Single-Phase DER under 150 kW), and a site-witnessed Interconnection Protection Settings and Commissioning (IPSC) test was required even under that small-unit document. A three-phase unit of any size, including a 30 kW synchronous mCHP unit, falls under DER-02 (Technical Interconnection Requirements for All Three Phase DER and Single-Phase DER 150 kW and Greater) and is processed under the same document, the same IEEE ICAP evaluation for machine-type generators, the same 110-day and 30-day submission packages and the same witnessed IPSC process as a 1 MW distribution-connected generator. Neither document provides a scaled pathway for a small synchronous machine or accepts a prior type-test report for the same unit model. What is not published, by any DFO we have dealt with, is the sizing methodology: the DFO's public material states only that systems are sized to the last twelve months of consumption, and the nameplate × 8,760 h calculation actually applied appears nowhere. CCL recommends that each DFO's terms and conditions or microgeneration customer guide be required to state (i) which technical requirements document applies to each combination of phase, size and generator type, (ii) any simplified pathway for synchronous units under 150 kW, and (iii) the sizing methodology in full.

5. **[Distribution facility owners only]** How many large microgeneration applications have you received in each year since 2023?

Click or tap here to enter text.

6. **[Distribution facility owners only]** How many large microgeneration projects have been cancelled in your service area after their application (i.e., Form A) was approved, and what are the general reasons for this (change to customer's plans, timeline delays, not enough available capacity, etc.)?

Click or tap here to enter text.

a. Are these projects typically cancelled after a specific step or milestone in the connection process (e.g. after a detailed level study, engineering/technical review, etc.)?

b. How likely are large microgeneration projects to be cancelled after their application is approved compared to small microgeneration projects? Please provide a percentage comparison, if available.

Click or tap here to enter text.

i. Are there certain types of large microgeneration projects (e.g., specific fuel types, projects in certain areas, etc.) that are more likely to be cancelled than other types of large microgeneration projects? Please explain.

ii. What sort of information could be provided to customers and microgeneration proponents, ahead of initial application submission, that could help decrease the number of cancelled large microgeneration projects?

7. Are participants in the microgeneration market, especially customers and microgeneration proponents, generally aware of the *Small Scale Generation Regulation?*

Yes. CCL is aware of the Small Scale Generation Regulation (SSGR) and has evaluated it as an alternative for the 20–150 kW mCHP segment. We do not consider it a substitute for the microgeneration stream for demand-matched generation, for the reasons in the next answer.

a. Would greater awareness of the *Small Scale Generation Regulation* alleviate some issues with microgeneration applications? Please explain

No, not for needs-based CHP customers. Greater awareness does not change the economics or the design intent of the SSGR stream:

1. Study and interconnection fees. Published DFO interconnection study fees for small-scale generation in the 20–150 kW range are on the order of $30,000–$55,000 per application. For a 20–50 kW mCHP unit that is a large fraction of, and at the low end can exceed, the installed cost of the unit itself. The same physical unit at the same site attracts no such fee as microgeneration.

2. Compensation structure. Small-scale generators are settled at pool price. An mCHP unit runs when the site needs heat, not when the pool price is high. In low-price hours the customer is penalised for operating when it must; in high-price hours the incentive is to generate beyond site needs. That is the opposite of the demand-matched, behind-the-meter operation that microgeneration is designed to encourage and that CCL's customers want. Our systems are sized to the customer's thermal demand and our revenue depends on operating within that envelope; we are not seeking to become a merchant generator.

3. Scale mismatch. The SSGR and distribution-connected generation processes are designed for units that can carry the cost of a full interconnection study and protection package. They are not designed for a 30 kW natural gas engine in a boiler room.

The correct outcome is not to redirect mCHP into the SSGR stream but to make the microgeneration stream size CHP units to the load they actually serve.

b. **[Distribution facility owners only]** Have you connected any customers as small scale or community generators?

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Cost estimates

1. Do cost estimates for a microgeneration project connection typically change over the connection process? If so, please describe the circumstances.

Yes. For a synchronous mCHP unit the initial indication is typically a standard microgeneration connection (bi-directional meter, utility-accessible disconnect, service verification). The estimate then changes when the DFO's technical review adds a site-witnessed Interconnection Protection Settings and Commissioning (IPSC) test – a relay test set injecting voltage and frequency into the unit's controller to prove the anti-islanding and over/under-voltage and -frequency trip settings, with DFO staff attending and a third-party test technician – and, in some cases, associated study or review charges.

The underlying cause is not a difference in protection functions. A synchronous mCHP unit and a PV inverter are both required not to island, to cease energising on voltage and frequency excursions, and to have a utility disconnect at the meter; synchronising is internal to the CHP package. The difference is that a certified inverter is accepted on its certification, while a synchronous unit's controller is re-tested in the field at every installation even though the controller hardware, certification and firmware are identical across every unit of the model. To date no DFO has sought to characterise these items as extraordinary under Regulation s.4(3) on a CCL project; this answer, and our comments in the Rule 024 matrix, anticipate the item most likely to be claimed.

a. What information could be provided, by distribution facility owners, customers, or both, that might reduce the likelihood or frequency of cost estimates changing significantly during the connection process?

From DFOs: (i) a published schedule of the protection, control and commissioning-test requirements applied to each technology class under 150 kW, with the DFO's typical cost for each element; (ii) an explicit statement of whether a design-level (type) witnessed IPSC test of a generating unit model and controller firmware version is accepted in lieu of a site-witnessed test for subsequent installations of the same model, and if not, why not; (iii) an explicit statement of which elements the DFO treats as ordinary and which it may seek to recover as extraordinary; and (iv) a preliminary cost range at Form A acceptance. From proponents: the unit's generator type, the controller and its certification, firmware version, the protection functions it provides, fault contribution, any export-limiting or reverse-power scheme, and any prior witnessed test report for the same model and firmware. Item (ii) accounts for most of the cost variance we expect between a PV connection and a synchronous mCHP connection of the same size.

2. In your opinion, at what point in the microgeneration connection process should a customer be informed of the potential to be charged for extraordinary costs?

> At Form A acceptance (within the 14 days in Rule 024 s.3(3)), as a preliminary indication with a range, and again with a final figure before the customer is asked to make any financial commitment or sign a connection agreement. A customer who learns of a potential extraordinary-cost claim only when the DFO files Form B under s.6(1) – which may be months after acceptance and after equipment has been ordered – has no realistic option other than to pay or cancel. We would support a rule that a DFO may not seek extraordinary-cost recovery for any item it did not flag, at least by category, at or within 30 days of acceptance, unless the need for that item arose from a subsequent change by the customer.

Technical standards

1. Do technical standards associated with a microgeneration unit connection typically change over the connection process? If so, please describe the circumstances.

> Yes, in two ways. First, requirements have been applied that are not in the DFO's published microgeneration terms and conditions and that emerge only during technical review – for synchronous units, principally the site-witnessed IPSC test and its associated review charges. Second, DFO interconnection requirements and customer guides for microgeneration and distributed generation have been revised during the life of a project, and the revised requirements have been applied to in-flight applications.
>
> Rule 024 itself contributes to this. It defines "inverter" (s.1(d)) but contains no definitions or provisions for synchronous generating units, so the Rule offers no anchor for what an "ordinary" connection of such a unit is, and each DFO fills the gap differently. In particular there is no provision recognising that a packaged unit's controller and firmware, once witnessed, are the same at every subsequent site.

   a. What information could be provided, by distribution facility owners, customers, or both, that might reduce the likelihood or frequency of technical standards changing partway through the connection process?

> From DFOs: publish a versioned technical requirements document per technology class for units under 150 kW, and commit that the version in force at Form A acceptance governs the project unless the customer changes the design. From the Commission: add to Rule 024 (or the Guideline) (i) a technology-neutral statement of the interconnection protection functions expected of any generating unit under 150 kW (anti-islanding, over/under-voltage and over/under-frequency cease-to-energise, utility-accessible disconnect at the meter), and (ii) a provision that a witnessed IPSC test of a generating unit model and controller firmware version, once performed and reported, is accepted for subsequent installations of the same model with unchanged firmware, subject to a functional site verification by the installer; a DFO requiring a repeat witnessed test should identify a site-specific reason. From proponents: a complete protection and control data sheet with the initial notice, against the published list, including the controller certification, firmware version and any prior witnessed test report.

Communication

1. Please briefly describe your experience with communication between distribution facility owners, customers, and any other participants during the microgeneration unit connection process.

Individual DFO staff have been professional and responsive. The difficulty is structural. The sizing test applied to mCHP is not written down anywhere the proponent can see, and the technical requirements that are published were written for large distribution-connected generators, so each exchange becomes a negotiation about what the rule is rather than about whether the project meets it. A second difficulty is that when the DFO does not accept the proposed size, the response has come as an informal request to resize rather than as a Form B notice of dispute, which leaves the proponent without a decision on the record and without a path to the Commission.

2. How often **do** distribution facility owners provide updates to customers on the status of their proposed microgeneration projects? Please comment on any differences between small and large microgeneration generating units.

For small microgeneration, updates have generally been provided only in response to proponent inquiries, not proactively. We cannot comment on large units.

3. In your opinion, how often **should** distribution facility owners provide updates to customers on the status of their proposed microgeneration projects? Please consider one or more of the below options, provide justification, and comment on any differences between small and large microgeneration generating units.

Our preferred combination is set out against the options below.

   a. Every 14 days

Not necessary as a fixed cadence; it would generate low-information updates and consume DFO resources. A maximum interval (no more than 30 days without a written status update while an application is open) is a better control.

   b. When the project enters a new phase

Yes. Every phase transition should generate a written update stating the phase completed, the phase entered, the expected duration, and any outstanding item the customer owes. This is the single most useful trigger.

   c. When the distribution facility owner receives new information that may necessitate changes to the microgeneration project's specifications

Yes, and it should be mandatory. Any new information that may change the unit's permitted size, the technical requirements, or the cost estimate (including any intention to seek extraordinary-cost recovery) should be communicated in writing within 14 days of the DFO becoming aware of it, with the reason and the customer's options.

   d. When information is about to become outdated due to lack of customer response

Yes. A warning with a stated deadline before information lapses is fair to both parties and prevents restarts.

e. Other

Where the DFO intends to dispute qualification or size, the update should be the Form B notice of dispute itself, issued within the 14 days in Rule 024 s.4(1), rather than an informal request to resize.

3. In your opinion, what are the most effective methods for distribution facility owners and customers to exchange necessary information in a timely fashion? In considering the below options, please take into account the required resources (time, staffing, or other).

Ranked below.

a. Direct emails/phone calls

Most effective for project-specific matters, and adequate in our experience. Phone calls or meetings, clarify issues up front quickly without back-forth and prevent decisions being made on incorrect assumptions like is typical during email correspondence. Should be supplemented by a written confirmation of any decision affecting size, requirements or cost.

b. In-person or virtual meetings

Useful at two points: a pre-application meeting for any non-PV technology (15–30 minutes is sufficient to confirm the sizing test and the technical checklist), and a meeting before any Form B filing.

c. Updates to distribution facility owners' websites as soon as relevant new general or system-wide information is known

Important for general and system-wide information: sizing methodology by technology class, technical requirements by technology class, current version numbers, hosting-capacity constraints, and fee schedules. This is the lowest-cost measure available and would prevent most of the issues described in this questionnaire.

d. General communication in a centralized hub, such as the AUC's website

Supported for cross-DFO material: a Commission-hosted comparison of the three streams (microgeneration, small-scale generation, distribution-connected generation), a summary of Commission decisions on s.1(1)(h)(ii) sizing, and any interpretive guidance the Commission issues on the sizing test.

e. Other

A standard status-report template (one page) common to all DFOs, so that customers with projects in more than one service area see the same information in the same form.

4. In your opinion, what changes to existing communication processes between microgeneration parties would lead to better outcomes, such as minimizing delays in the connection process?

Three changes, in order of value: (1) publication by each DFO of its sizing methodology and technology-class technical requirements, so that communication is about the project and not about the rule; (2) a requirement that any decision that the proposed unit does not qualify, or must be reduced, be issued as a Form B notice of dispute with reasons, rather than informally; and (3) a requirement that the intention to seek extraordinary-cost recovery be disclosed, at least by category and range, at or shortly after Form A acceptance. Each of these converts an open-ended negotiation into a defined step with a defined output.

5. Please briefly describe your experience with microgeneration applications where the proposed size must be reduced for legislative, technical, safety, or other reasons. How has this been communicated?

On each of CCL's mCHP notices to date, the DFO has taken the position that the proposed electrical nameplate, multiplied by 8,760 h/yr, exceeds the site's annual electrical consumption, and that the unit must be reduced to a nameplate for which that product is at or below consumption. The site's thermal demand –the load the unit is sized to serve, and the load that determines whether the existing boiler can be retired – has been treated as irrelevant. The communication has been by email and telephone from DFO staff, without a Form B notice and without reference to any published methodology. The practical consequences are described in our answer to Timelines Question 3, with the unit being asked to be reduced in size or with a specific monthly production schedule.

The consequence of the reduction is not proportional. A unit sized to the site's electrical consumption on the DFO's method is typically 50–65% of the size the site's peak useful thermal demand would justify and cannot replace the customer's existing boiler. The customer then keeps, maintains and eventually replaces redundant heating equipment; occupying the space that the CHP would occupy in their facility. If the CHP unit is installed, the thermal output is under-used; and total site fuel consumption and emissions per unit of useful energy are higher than with a correctly sized unit. In some cases the only way to correctly size CHP output is to add new electrical loads that did not previously exist and are made redundant by CHP thermal output such as heat pumps, which increases rather than reduces site energy consumption or inflates capital costs – an outcome directly contrary to the Regulation's purpose. For most of our customers the boiler replacement is the project; a unit that cannot retire the boiler has no economic case, and the project is cancelled.

   a. When the rationale for such reductions is communicated, what options for proceeding with the microgeneration project are generally provided to customers?

Two options have been presented: reduce the unit's electrical nameplate to satisfy the 8,760 h test, or apply instead under the Small Scale Generation Regulation. Neither is workable for a boiler replacement, for the reasons given above (thermal under-sizing in the first case; study fees and pool-price exposure in the second). The option that should exist – size to the site's peak useful thermal demand established from gas bills and engineering assessment, operate heat-led when thermal demand is present and electricity-led when that service is required, and export and re-import the electrical surplus under s.7 – is not available under the electricity-only test, and that is the gap CCL asks the Commission to address.

6. **[Distribution facility owners only]** What is your rationale or threshold for when to provide updates to customers on the status of their microgeneration projects? Please explain with reference to the factors and circumstances that may be considered.

Click or tap here to enter text.

a. Is providing customers with more frequent status updates a feasible and helpful option in general? Please explain, including any different considerations for small and large microgeneration projects.

General

1. **[Customers only]** Has any salesperson or company attempted to sell you or a member of your household a solar microgeneration system, especially door-to-door? If yes, please briefly describe your experience.

   Click or tap here to enter text.

2. **[Distribution facility owners only]** Do you have the necessary information and tools to (a) monitor and (b) manage existing microgeneration generating units that may be out of compliance with the *Micro-generation Regulation* (likely due to consistent generation in excess of annual consumption)? If not, please explain what you would require to do so.

   Click or tap here to enter text.

3. If there is any other microgeneration-related information that you feel is important for the AUC to know, please briefly describe it here.

   CCL asks the Commission to note the following, which we consider the most important microgeneration issue for non-solar, dispatchable units in Alberta. The supporting analysis is in our answer to Timelines Question 3.

   1. Principal request: a thermal-demand sizing standard for CHP in Rule 024. An mCHP unit is heating plant that co-produces electricity. Its size is properly set by the site's peak useful thermal demand – for process, space heating, water heating or any other useful purpose – because heat cannot be stored over long periods (cost effectively) and must be produced when and at the rate it is needed, whereas surplus electricity can be exported and re-imported through the grid under s.7 of the Regulation. Sizing to annual electrical consumption, or to annual-average thermal load, produces a unit that cannot carry the thermal load when it occurs and leaves the existing boiler in place; retiring that boiler is what delivers the capital, efficiency and emissions benefit of CHP. A CHP unit's availability is comparable to that of the boiler it replaces; a site's backup heating arrangement is the same after the CHP is installed as before, so the replacement does not introduce a new outage risk. CCL asks that Rule 024, Form A and the Guideline provide that a CHP unit's thermal output may not exceed the site's peak useful thermal demand as established by engineering assessment reconciled to 12–36 months of historical gas consumption; that electrical nameplate follows from the unit's heat-to-power ratio; and that the operating modes and the control that enforces them are documented in the notice. No thermal metering is required. The standard is a cap; proponents may size below it and may retain an auxiliary heat source.

   2. The Regulation recognises CHP; the sizing mechanism does not. Section 1(1)(l)(ii)(B) defines a CHP unit's output as "the total energy produced from the simultaneous generation of electric energy and production of thermal energy from the same fuel source" for the 418 kg CO_2e/MWh alternative-energy test, which a natural-gas unit meets only when its recovered heat is used. The eligibility definition therefore already assumes a unit sized and operated to a real thermal load, and correctly excludes electrically-dominant sites; CCL accepts that. The sizing test in

s.1(1)(h)(ii), and its administration through Rule 024, Form A and the Guideline, were built around PV and have never been tested against a CHP unit. The Commission's reasoning in Decision 27017-D01-2022 (NuVista) – that generation "reasonably scaled to meet the electricity and thermal needs" of a site is reasonable – is the right principle and should be carried into Rule 024.

3. The legal path. Independent counsel to CCL (McLennan Ross LLP, March 2026) concluded that s.1(1)(h)(ii) refers to electrical consumption only and that recognising thermal demand in sizing requires a targeted amendment to the Regulation, with corresponding changes to Rule 024 and Form A. CCL has raised that amendment with Alberta Affordability and Utilities. We ask the Commission to (a) communicate to the Minister that the sizing mechanism does not accommodate a technology the Regulation expressly recognises, and that the Commission supports the targeted amendment; (b) draft the Rule 024, Form A and Guideline provisions in item 1 now, so that they take effect with the amendment; and (c) in the interim, within its existing interpretive latitude (Decisions 23412-D01-2018 and 28319-D01-2023), direct that the production term for dispatchable units be expected annual output under the declared operating mode to meet combined energy demands rather than nameplate × 8,760 h, and that a DFO that does not accept the declared production issue a Form B notice of dispute with reasons within the 14 days in s.4(1).

4. Rule 024 should become technology-neutral in its definitions and forms. The Rule defines "inverter" and nothing else about generator type. We recommend adding definitions of "inverter-based generating unit", "synchronous generating unit" and "combined heat and power unit", and Form A fields for peak useful thermal demand and its basis, annual thermal consumption from gas bills, thermal and electrical output, heat-to-power ratio, operating modes and control, export limit, generator type and on-board protection, and heating equipment replaced.

5. Commissioning and extraordinary costs. A packaged mCHP unit's controller, certification and firmware are identical at every installation; a witnessed IPSC test performed once for the model and firmware version should be accepted for subsequent installations of the same equipment, and the cost of a repeat test should not be recoverable as extraordinary. Our comments on the proposed s.6(2) are in the Rule 024 matrix: costs that are routine for every unit of a recognised technology class are ordinary costs of that class, and the comparative analysis in s.6(2)(d) should be required to compare like with like.

6. Why this matters beyond CCL. A CHP unit sized to the site's thermal demand is firm, dispatchable, behind-the-meter generation with a combined efficiency near 90% (LHV); it displaces boiler fuel at the customer's site and retires a heating asset rather than adding one; and at most sites it runs hardest in the coldest months, when Alberta's system peak occurs and Wind/PV output is lowest. The current administration of the sizing test forces these units to be undersized to the point where they cannot do the job they are installed for, or pushes them into a merchant stream they are not designed for. That outcome serves neither the customer, nor the distribution system, nor the purposes of the Regulation.

CCL is prepared to provide technical input, customer gas and electrical consumption data, engineering assessment methodology, and case studies to the Commission and to DFOs, and to participate in any further consultation on Rule 024, Form A or the Guideline.