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# The SGER Amendments and the New Treatment of Cogeneration

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**Regulation Commented On:** *Specified Gas Emitters Amendment Regulation*, Alta Reg 104/2015

In a previous post I reported on the Minister's speech announcing a two-step procedure for developing a new climate change policy for Alberta. The first step involved changes to two of the key variables in the current *Specified Gas Emitter Regulation* (SGER), Alta Reg 139/2007 while the second step is the more comprehensive review to be conducted by Dr Andrew Leach to assess the full range of options for the management of greenhouse gas emissions in the province. At the time I wrote that post I had not examined the details of the amendments to the SGER to see what other changes (if any) were being proposed. This post picks up where the last left off.

Here is what I wrote in the previous post. The first paragraph offers a brief description of the SGER regime. The second paragraph describes the key changes to that regime.

> The SGER imposes greenhouse gas emissions intensity reduction obligations (ultimately 12%) on regulated emitters (facilities that emit in excess of 100,000 tonnes of $CO_{2e}$ per year). A facility may achieve compliance in one of four ways: (1) meeting its target by producing its product with lower carbon inputs, (2) Alberta based offset credits (emission reductions over a business as usual scenario achieved by a non-regulated entity in accordance with an approved protocol), (3) emission performance credits (credits achieved by a regulated facility which beats its compliance target), or, (4) a contribution of $15 per tonne (for excess emissions over the compliance target) to the Climate Change and Emission Management Fund (the so-called compliance price).
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> The province will extend the SGER but will change two of the three key variables embedded in the regulation. While the amendments to the regulation have yet to be gazetted it appears that the regulation will be extended until the end of 2017. The coverage of the regulation will not change, i.e. the regulation will continue to apply only to emitters emitting more than 100,000 tonnes $CO_{2e}$. However, both the ambition (or stringency) of the regulation and the compliance price will change. Thus, regulated emitters will be required to make emission intensity improvements of 15% in 2016 and 20% in 2017, and the compliance price will change to $20 per tonne in 2016 and $30 per tonne in 2017. The Minister estimates that these initiatives will reduce emissions by 13 megatonnes per year by 2017.

As one would expect, the amendments to the regulation implement the changes to the stringency requirement (new s.4). However no change to the regulation is needed to implement the new compliance prices because s. 8(2) of the SGER stipulates that this is to be effected by Ministerial Order rather than by Regulation:

> The Minister may, by order, establish the amount of money that a person responsible must contribute to the Fund to obtain one fund credit equal to a one tonne reduction in emissions, expressed on a $CO_2$e basis.

A moment's reflection will confirm just how bizarre this is: one person gets to establish the marginal price of carbon in Alberta! While the reality no doubt is that the price of carbon is in fact a matter for cabinet, one wonders why such an important issue does not require an amendment to the regulation, if not an amendment to the governing legislation.

In addition to the changes to the stringency requirements, the amendments deal with two other matters, the treatment of cogeneration and the status of Ministerial guidance and standards, as well as some house-keeping issues.

**The Treatment of Cogeneration**

Cogeneration, also known as combined heat and power (CHP), is the simultaneous production of electricity and heat from a single fuel source. Cogeneration offers significant benefits over other forms of generation principally for efficiency reasons. The average global efficiency of traditional generators ranges between 35% and 37%. The most efficient turbines can bring efficiency close to 45% or 50%, but overall they remain significantly less efficient than cogeneration plants. Cogeneration allows 75% to 80% of fuel inputs, and up to 90% in the most efficient plants, to be converted into useful energy. Cogeneration does not, in itself, increase the power supply, but uses one fuel input to produce two outputs, i.e. heat and electricity. By making more efficient use of fuel inputs, cogeneration allows the same level of end-use energy demand to be met with fewer energy inputs. Thus, it reduces energy consumption, greenhouse gas emissions and other air pollutants. By locating close to load, cogeneration may also defer the need to construct new transmission and may reduce overall line losses.

According to the Alberta Electric System Operator's 2014 Long-term Outlook, Alberta (as of the end of 2013) had an installed capacity of 4,250 MW of cogeneration (29% of the total installed generation capacity of MW 14,568) mostly in the oil sands sector (both mining and in situ operations). In situ operations require electricity for their operations and a large amount of steam. Steam can be produced through a stand-alone natural gas fired boiler or through cogeneration or some combination of the two. An in situ operator electing to construct cogeneration may size the generation to meet its steam needs or its electricity needs. If the project is sized to meet steam needs it will produce electricity considerably in excess of its requirements. This surplus must be exported to the Alberta grid. In this scenario oil sands operators will tend to pursue a strategy of bidding power into the pool at zero or close to zero to ensure dispatch (see Oil Sands Community Alliance, 2014 Oil Sands Co-generation and Connection Report, at 29 – 30). As such, cogeneration can provide lower emissions intensity base load to the system.

In sum, cogeneration offers considerable benefits to Alberta's electricity system but it is not a panacea in the context of greenhouse gas emissions. To the extent that natural gas rather than biofuels remain the fuel of choice for cogeneration projects, cogeneration will still result in greenhouse gas emissions (unless captured and sequestered) although such emissions will be reduced when compared with stand-alone gas fired steam boilers and combined cycle gas generation each producing a single product.

The question for present purposes then is how the benefits of cogeneration are or should be recognized in the SGER scheme described above.

**The Treatment of Cogeneration in the Pre-Amendment Version of SGER**

The pre-amendment version of SGER said nothing whatsoever about cogeneration. As a result, any recognition of the greenhouse gas benefits of cogeneration had to be achieved within the general provisions of the regulations. It is not immediately obvious how this can be done and the resulting recognition was exceptionally opaque. While the offset scheme might offer the most obvious mechanism for accommodating cogeneration, this option will not generally be available, principally because a cogeneration facility will typically form an integrated part of an industrial facility which will itself be a regulated facility. A project can only qualify as an offset project if it is not part of a regulated facility (SGER, s 7). The whole purpose of the offset scheme is to create an incentive to reduce emissions over business as usual (BAU) in the unregulated sector.

The only other alternative was to recognize cogeneration facilities as capable of producing emissions performance credits (EPCs) and this indeed proved to be the Department's chosen vehicle for recognizing the emission reduction opportunities associated with cogeneration. At the risk of oversimplifying, a regulated project with cogeneration can obtain EPCs based on the difference between deemed emissions and actual emissions. Deemed emissions are calculated by reference to each of the two products, steam and electricity. Deemed emissions for steam are calculated on the basis that in a BAU case the steam would have been produced by a gas fired boiler operating with an efficiency of 80%. Deemed emissions for electricity are calculated on the basis that electricity would otherwise have been produced by a combined cycle gas turbine with an emissions intensity of 0.418 tonnes $CO_2$e/MWh. In addition, while the deemed baseline steam emissions were subject to the 2% per annum improved intensity requirements, the deemed emissions associated with electricity generation were not. All of this is (or at least was) achieved through technical guidance documents including Government of Alberta, Alberta Environment and Sustainable Resource Development, *Technical Guidance for Completing Specified Gas Compliance Reports*, Version 7.0, January 2014, at s 4.3.

**Critiques of the Pre-Amendment Treatment of Cogeneration Under SGER**

There is a lively debate about the treatment that has been accorded to cogeneration under the SGER. For some there is a threshold question as to whether cogeneration should generate credits at all. For others the debate is more about the level of crediting extended to cogeneration – is it too generous, is it not generous enough? And finally, from a legal perspective, there is a question about the lack of transparency of the crediting rules for cogeneration.

The threshold question is generally framed in terms of additionality which is a concept more frequently associated with offsets rather than EPCs. The concept is relevant here because of the way in which cogeneration facilities generate credits. In order to qualify a project for *offset* credits the proponent of the project (or in Alberta the developer of the crediting protocol) must establish additionality. Additionality means that but for the availability of carbon credits the proponent would not have engaged in this particular emissions reduction activity. In this context this would mean that the project proponent would not install cogeneration but for the availability of credits but would instead produce steam in a gas fired boiler and purchase electricity from the grid. If, however, the proposed activity is BAU (i.e. the proponent would engage in it anyway) then it is inappropriate to award any carbon credits since to do so simply undermines the stringency of the targets that the regulated emitter must meet. While the SGER only refers to additionality in the context of offsets and not in the context of EPCs, it is evident that the deemed approach to the calculation of EPCs for cogeneration is conceptually similar to the treatment of offsets. Hence, in order to qualify for EPCs some argue that a proponent of a cogeneration project should have to meet an additionality test. It is possible that some projects (or projects of a certain size) would meet an additionality test while others would fail. For example, the electricity market price risks associated with sizing cogeneration to meet project steam needs might suggest that a proponent requires a carbon price incentive in order to make that investment, whereas the installation of cogeneration to meet project electricity needs might be nothing more than BAU.

Beyond the threshold question there is also a debate about the level of crediting extended to cogeneration. As noted above, the calculation of EPCs turns on the difference between deemed emissions and actual emissions; the higher the deemed emissions the more generous the crediting. On one side of this debate are those who argue that the 0.418 tonnes $CO_2e$/MWh reference used to calculate EPCs provides only limited recognition of the efficiency benefits of cogeneration. The recognition is said to be limited because the Alberta power grid has an emission intensity that is significantly higher than 0.418 tonnes $CO_2e$/MWh. This leads some to take the position that EPCs should be calculated based on the annual average Alberta power grid emission intensity (most recently stated by ESRD to be 0.88 $CO_2e$/MWh) to recognize the grid displacement benefits of cogeneration. Still more favourable would be a deemed intensity factor based on the assumption that in situ cogeneration curtails coal generation. On the other hand, if cogeneration is actually curtailing generation from renewables then the deemed emissions intensity factor should be lower.

A final criticism is that whatever the merits of crediting for cogeneration the current scheme is far too opaque, especially when one considers the scale of crediting attributed to cogeneration projects. The following table produced by the Department (April 2015) documents the compliance cycle for regulated facilities.

| **Compliance Cycle** | **Emissions Reductions at Facility (Mt CO2e)** | **Offset Credits Submitted (Mt CO2e)** | **Recognition of Cogeneration (Mt CO2e)** | **Total Reductions (Mt CO2e)** | **Fund Payment ($Million)** |
|---|---|---|---|---|---|
| 2007 (half year) | 1.60 | 0.88 | 1.28 | 3.76 | 41.3 |
| 2008 | 1.35 | 2.68 | 2.58 | 6.61 | 85.4 |
| 2009 | 0.89 | 3.74 | 2.66 | 7.29 | 61.3 |
| 2010 | 1.02 | 3.85 | 2.55 | 7.43 | 67.4 |
| 2011 | 3.06 | 5.40 | 2.51 | 10.96 | 55.0 |
| 2012 | 1.20 | 3.20 | 3.41 | 7.80 | 87.7 |
| 2013 | 0.45 | 2.04 | 4.17 | 6.66 | 98.6 |
| 2014 | 5.01 | 2.55 | 3.11 | 10.66 | 83.4 |
| Total | **14.57** | **24.34** | **22.26** | **61.17** | **577.9** |

Note: Mt = Million Tonnes

Two features of the table are significant. The first is that "Recognition of Cogeneration" is accorded separate recognition on a par with offset credits and fund payments notwithstanding the fact that while these latter two categories are expressly recognized in the SGER there has (until this round of amendments) been no separate recognition in the SGER for cogeneration. Second, the table shows that the cumulative effect of recognizing EPCs associated with cogeneration is very similar in terms of scale to the crediting associated with all offset programs combined. With credits available at this scale, the availability of this crediting option arguably should be clearly articulated in the regulations themselves rather than in policy-level guidance documents. There are no doubt all sorts of reasons why offset projects have not generated more credits (including the low compliance price and the transaction costs associated with getting protocols approved and projects and credits registered) but the point here is simply that while the treatment of offsets under the SGER is completely transparent, the historical treatment of cogeneration is completely opaque.

**The Treatment of Cogeneration in the Amendment**

As noted above, prior to the amendment, a regulated facility could meet its net emissions intensity limit in one of four ways: actual efficiency gains, offset credits, EPCs and fund contributions. The amendments add one "additional" (see new s.6(1)) way of meeting the target: a "cogeneration compliance adjustment" (CCA) which is to be defined in the Standard for Completing Greenhouse Gas Compliance Reports. At the same time, the government has amended s.9 (dealing with EPCs) to add a subsection specifying the maximum number of EPCs that the Director can issue in any year. The formula specifies that the Director must subtract the facility's CCA for that year. The inference is clear. Cogeneration projects associated with regulated facilities will no longer generate EPCs but instead what appears to be a much less fungible CCA. While we have yet to see the precise rules for calculating a facility's CCA, such a CCA would appear to be conceptually different from EPCs, offset credits and fund credits. While s.10 of SGER states that these compliance tools are merely "revocable licences" and that nothing in the regulation "ensures or guarantees" the availability of offsets or EPCs, it would seem that the drafter intended that the CCA should not even have the status of a tradeable revocable licence. Thus it would seem that a CCA is not fungible and can only be used by the facility owner, and, on the face of it, only in that particular compliance year. Thus, while an EPC is tradeable, bankable and can be used in different compliance periods (even when the compliance cost changes), none of that would appear to be the case for a CCA. On the other hand, it should be noted that while the director may require (s.26 as am) the facility owner to take prescribed remedial action where problems are subsequently identified with respect to emissions offsets or EPCs, there is no corresponding authority with respect to CCAs.

In sum, the amendment has changed the arrangements for crediting the greenhouse gas benefits of cogeneration at both the formal and substantive levels. At the formal level, cogeneration earns express recognition in the SGER as a means for attaining compliance. This is clearly a step in the right direction in terms of both the rule of law and transparency. However, the SGER is not as clear as it could be with respect to the status of the new CCA and it is unclear why the new prescribed remedial action provision applies to offsets and EPCs but not CCAs. At the substantive level it appears that some steps have been taken to limit the benefits associated with cogeneration credits. While much will depend on the terms of the Standard my reading of the amendment suggests that the CCA will not be tradeable or bankable.

**Clarification of the Status of Departmental Guidance**

Sections 61 and 62 of the *Climate Change and Emissions Management Act*, SA 2003, c. C-16.7 provide as follows:

**Adoption by reference**

**61**(1) A regulation under this Act may adopt or incorporate in whole or in part or with modifications documents that set out standards, practices, codes, guidelines, objectives, methods or other rules of any government, organization or person, including, without limitation, any standards, practices, codes of practice, guidelines, objectives or methods developed by the Minister under section 62, as they read at a particular time or as amended or replaced from time to time relating to any matter in respect of which a regulation may be made under this Act.

(2) Subsection (1) applies to any standard, practice, code, guideline, objective, method or other rule that has been adopted or incorporated into a regulation before or after this section comes into force.

(3) Where a standard, practice, code, guideline, objective, method or other rule is adopted or incorporated by regulation under this Act, the Minister shall ensure that a copy of the standard, practice, code, guideline, objective, method or other rule is made available to a person on request.

**Codes of practice, guidelines**

62 The Minister may develop standards, practices, codes of practice, guidelines, objectives or methods relating to any matter in respect of which a regulation may be made under this Act.

The Department has issued a number of important technical guidance documents with respect to the interpretation and application of SGER. These documents include guidance as to the completion of baseline emission intensity applications, compliance reports and verification approaches. The SGER did make some reference to Ministerial guidelines issued under s.62 of the Act (see, for example, ss.7(2)(d), 8(3)(e) & 9(2)(e)) but there was perhaps some room for doubt about the precise status of these guidance documents. While any such doubts may not be completely resolved (since the Regulation still contains the above references) the Regulation has clarified the status of a number of standards (no longer referred to as Technical Guidance). Thus a new s.3.1 provides that

The following standards are adopted and form part of this Regulation:

(a) Standard for Completing Greenhouse Gas Baseline Emissions Intensity Applications;

(b) Standard for Completing Greenhouse Gas Compliance Reports;

(c) Standard for Greenhouse Gas Emission Offset Project Developers;

(d) Standard for Greenhouse Gas Verification.

And in each case the Standard is defined as the Standard "published by the department, as amended or replaced from time to time".

**The Period of Extension**

The amendment extends the Regulation from June 30, 2015 to December 31, 2017. It remains to be seen whether the Regulation will be further extended after that or whether Dr. Leach's review will result in more comprehensive changes to Alberta's carbon management policies.

**Some Final Thoughts**

I have three final thoughts. The first relates to consultation, the second relates to market considerations, and the third relates to overall cogeneration policy.

As to the first, I think that these amendments bring about a significant change to the carbon treatment of cogeneration. I think that the more explicit and transparent treatment of cogeneration is a good step forward but I think that there is still a need for more light to be shed on the details. My comment relates to the degree of consultation that accompanied these changes. I simply do not know how broadly the Department consulted on these changes. Did it talk to industry? Did it talk to ENGOs? Did it consult them on the details like fungibility and "bankability"? Did it prepare an options paper? I don't know the answer to any of the above. I can certainly say that there was no broad public consultation and no pros and cons options paper posted on the Department's website. Indeed, the website still does not contain a link to the new "Standards" that are supposed to be incorporated in the regulations. Now I understand that this government has not been in office long (although I suspect much of the contents of this package pre-date the current administration) but I for one am hoping that this government might make public policy differently from its predecessors and that consultations will be supported by published and reasoned options papers or white papers.

Second, as Duff Harper recently observed in a Blakes Bulletin, the compliance options for regulated emitters on a go-forward basis will, in practical terms, be very limited. This is because the $15 per tonne compliance price has crippled the offset market; that price is simply too low, and by waiting to the bitter end of the drop-dead date for the SGER (and then extending the bitter end - twice) the previous administration failed to provide a concrete and positive signal to the market as to the future compliance price. The new administration has now sent that signal but it is too little and too late. Not much will happen in the next two years to produce lots more offsets for compliance purposes over that period. And the message that is being sent to possible offset developers after 2017 is equivocal. On the one hand the amendments will increase demand for offsets and raise the compliance price, but on the other hand there is no certainty more than two years out, given the more comprehensive review that Dr. Leach will lead, that the offset program will still be part of Alberta's compliance scheme. Thus, while existing offset project owners may in a sense earn a windfall over the next two years, two years is insufficient time to bring on many more new offset projects. One result of this might be positive. Given limited compliance options regulated projects may actually invest in emissions intensity improvements – but again a two year signal hardly seems adequate as a basis for making significant capital investments. The other result, compliance through payments into the Fund, seems far more likely. But this may also mean that government will be led to (re)consider the purpose of the Fund given what will undoubtedly be significantly increased contributions. For more discussion of this see the paper by Beck and Wigle referenced in this earlier ABlawg post.

Finally, cogeneration is an important part of Alberta's electricity mix and its importance is likely to grow for two reasons. First, oil sands projects will continue to need process heat and electricity as part of their extraction, processing and upgrading. These requirements can be most efficiently met by on-site cogeneration facilities which provide stream and electricity for the operation. Second, the efficiencies associated with cogeneration mean that there are also greenhouse gas mitigation advantages associated with this technology, especially when compared with stand-alone carbon-based generating facilities. Despite its importance it is fairly clear that Alberta does not have a coherent cogeneration policy. Instead, the province has a de facto position on cogeneration created by the interaction of a number of different policy documents and statutes including the Industrial Systems Policy Statement (1997), the Transmission Development Policy (2003), the *Electric Utilities Act*, SA 2003, c.E-5.1, the *Hydro and Electric Energy Act*, RSA 2000, c. H- 16 the Transmission Regulation, Alta Reg 86/2007 and the SGER and the technical guidance documents designed to implement SGER. Given the scale and importance of cogeneration to the province's industrial sector, and indeed to the province generally, it is perhaps time that Alberta developed a clear and coherent policy on cogeneration.