National Energy Board
Office national de l'énergie

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Mr. Paul Barnes
Manager, Atlantic Canada
Canadian Association of Petroleum Producers
905, 235 Water Street
St. John's, NL A1C 1B6
Facsimile (709) 724-4225

Project Working Group Detailed Response to the Canadian Association of Petroleum Producers' (CAPP) Comments on the Draft Goal Oriented Drilling and Production Regulations (DP Regs)

Further to the Project Working Group's[1] (PWG) 20 October 2005 letter to CAPP, attached is its detailed response to CAPP's comments on the draft goal oriented DP Regs. The National Energy Board provides this response on behalf of the PWG.

Revised draft goal oriented regulations are also attached.

Next Steps in Consultation

In its 20 October 2005 letter, the PWG noted that the next step in the consultation process on the DP Regs would be to meet with CAPP to discuss the PWG's detailed response. However, as discussed between yourself and Kent Lien, on 26 January 2006, it now appears that the preferred, and most timely and effective method of consultation, is to consult on the entire draft of the goal oriented DP Regs. That is, the goal oriented sections will be inserted into the draft DP Regs which have been reviewed by the Federal Department of Justice and the entire regulation will form the basis for consultation. It is anticipated that the draft goal oriented DP Regs will be available for comment by CAPP, and other parties, in spring, 2006. Upon receipt of CAPP's comments, the PWG could then meet with CAPP to discuss its comments prior to final drafting of the DP Regs for publication in the Canada Gazette.

Should circumstances change such that CAPP would prefer a meeting to discuss the PWG's attached response prior to release of the entire draft DP Regs for comment, the PWG would be pleased to accommodate such a meeting.

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[1] National Energy Board, Natural Resources Canada, the Province of Newfoundland and Labrador, the Province of Nova Scotia, the Canada-Newfoundland and Labrador Offshore Petroleum Board, the Canada-Nova Scotia Offshore Petroleum Board, and the Department of Indian Affairs and Northern Development.

HSE Case and Formation Flow Testing

The PWG and the Frontier and Offshore Regulatory Renewal Initiative[2] (FORRI) have continued to discuss issues pertaining to the incorporation of the requirement for an HSE Case within the
DP Regs. Current thinking is that major changes to the DP Regs will not be required to facilitate the submission of an HSE Case by an operator to fulfill the requirements for safety and environmental protection plans. Rather, wording in the DP Regs will be slightly modified to better accommodate submission of a HSE Case.

Changes to the Drilling Regulations under the Offshore Accord Acts[3] regarding formation flow testing are currently undergoing review as part of the regulatory process. The intent is to promulgate these changes some time in 2006. The same wording has been proposed for the DP Regs, as outlined in the attached document.

Guidance Notes

The PWG notes that it is aware of the challenges in reviewing the goal oriented DP Regs in the absence of the accompanying guidance notes. However, this phase of the DP Regs project has now begun and the PWG welcomes CAPP's participation. The PWG will soon be discussing with CAPP its participation in the development of the guidance notes.

The PWG looks forward to continued work with CAPP on this file. If you have any questions, or wish to discuss the project, please contact the Project Manager, Kent Lien, at (403) 299-2762 or by e-mail at klien@neb-one.gc.ca. For communication in French, please contact Jodi Lea Jenkins, Assistant Project Manager, at (403) 299-3677 or by e-mail at jjenkins@neb-one.gc.ca.

Yours truly,

Michel L. Mantha
Secretary

Attachments:
Detailed response from PWG
Revised draft DP Regs

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[2] Comprised of the same stakeholders as the PWG and representatives from several other provincial and territorial governments.

[3] *The Canada-Newfoundland Atlantic Accord Implementation Act; the Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act; the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act; and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act.*

c.c.

Name	**Organization**
Howard Pike, Chief Safety Officer	Canada-Newfoundland and Labrador Offshore Petroleum Board, Fax (709) 778-1473
Wayne Chipman, Chief Conservation Officer	Canada-Newfoundland and Labrador Offshore Petroleum Board, Fax (709) 778-1432
Stuart Pinks, Chief Safety Officer	Canada-Nova Scotia Offshore Petroleum Board, Fax (902) 422-1799
Sandy MacMullin, Director, Resource Assessment and Royalties	Nova Scotia Department of Energy, Fax (902) 424-0528
Bruce Cameron Director, Policy and Analysis	Nova Scotia Department of Energy, Fax (902) 424-0528
Fred Allen Manager, Regulatory Affairs	Newfoundland and Labrador Department of Natural Resources, Fax (709) 729-2508
Wes Foote Chief Petroleum Engineer	Newfoundland and Labrador Department of Natural Resources, Fax (709) 729-2508
Gerard Peets Policy Advisor	Natural Resources Canada, Frontier Lands Management Division, Fax (613) 943-2274
Gilles Morrell, Manager, Energy and Environmental Policy	Indian and Northern Affairs Canada, Northern Oil and Gas Directorate, Fax (819) 953-5828
Alain Lefèbvre, Directeur	Ministère des Ressources naturelles et de la Faune, Direction du développement des hydrocarbures, Fax (418) 528-0690
Albert West, Senior Petroleum Advisor	Government of the Northwest Territories, Fax (867) 873-0254
Boris Tyzuk	BC Offshore Oil and Gas Team, Fax (604) 660-2636
Dick Heenan, Drilling Consultant	Paramount Resources Ltd, Fax (403) 290-6208
Don Herring, President	Canadian Association of Oilwell Drilling Contractors, Fax (403) 263-3796
Doug Carter, Senior Reservoir Engineer	Devon Canada Corporation, Fax (403) 213-8100
Ed Kustan	Paramount Resources Ltd, Fax (403) 290-6208
Jim Kennedy, Manager QA/QC	Nabors Drilling Ltd, Fax (780) 955-1333
John McDonald	Canadian Southern Petroleum Ltd., Fax (403) 261-5667
Karl Ruud	Akita Drilling, Fax (403) 292-7990
Kevin Ullyot	EnCana Corporation, Fax (403) 645-3400
Neil W. Drummond, Regulatory Manager	Imperial Oil Resources Limited, Fax (403) 232-5861
Stephan Lopatka Senior Advisor; Minerals, Oil & Gas	Nunavut Tunngavik Inc. Department of Lands and Resources, Fax (867) 983-5624
Ted O'Keefe, Regulatory and Environmental Lead-Hibernia	ExxonMobil Canada Ltd., Fax (709) 753-0364

PWG Detailed Response to 29 June 2005 CAPP Comments on the Draft Goal Oriented DP Regs March 2006

Note: CAPP Comments from its 29 June 2005 submission have been copied verbatim and are in Times New Roman font.
The PWG response is indented and is in Arial font.

Section 1: General Well Control Requirements

Section 63. (1) (c): We suggest inserting the word "planned" in front of "well activities". The regulations have to be absolutely clear in this regard. One could interpret the proposed wording to imply that well control equipment must meet every conceivable need required for all drilling, completion and work over operations, even though this is probably not the regulator's intent.

> The PWG does not agree. Although it would be an overstatement to say that well control equipment must meet every "conceivable need", well control equipment must be appropriate for any perceived possible events. The PWG also notes that in emergency situations, other provisions in the regulations (*e.g.* section 18) will apply and thus, it isn't necessary to meet "every conceivable need".

The current wording in this section could require a copy of API RP 53 (among other documents) on every facility location to confirm the testing frequency which we believe will not increase regulatory efficiency.

> The PWG does not agree that the regulation implies that a copy of API 53 would need to be on every facility. It is up to the operator to determine, to the Board's satisfaction, how it intends to meet the intent of the regulation. However, if it wants to do that by having a copy of API 53 at each facility, it can.

As well a frequency of pressure testing and function testing of BOP's should be specified (e.g. weekly function tests and pressure tests every 15 drilling days for onshore wells – every 14 operating days for offshore. It may be helpful to note that API RP 53 specifies weekly function tests and 21 days for pressure tests.

> Testing frequency is covered in section 90.
>
> Additional details on specifications and standards will be provided in the guidance notes.

Section 63. (2): Consider revising this paragraph to read as follows: "After setting the surface casing, every operator shall ensure that during all well operations, there are at least two independent and tested well barriers in place except when working in unperforated cased hole (that has been pressure tested). Short term expectations, equivalencies, or special operations will be approved on a case by case basis by the Board."

There will be times when two effective and tested barriers will not be in place, and there is the question of defining what is considered an independent barrier, and what is considered tested. For example is a BOP stack with two pipe rams, a blind/shear ram, and an annular, considered one barrier or four? Regarding testing – shear rams are never field tested to ensure they will shear and still hold pressure. Effectiveness of annular or blind/shear rams, or downhole safety valves on cutting or sealing on logging cable or as well slickline is not field tested.

We also question the length of time, to conduct short interval operations where one of the primary barriers is not effective. An example may be when pulling a long section of perforating guns through the BOP stack. The regulation as written would force use of shear rams on many operations, and even then there may be drillstring tools in use that could not be effectively sheared and/or sheared with the result of obtaining a perfectly sealed wellbore, and beyond that, some configurations could not be field tested to provide comfort that it would work dependably.

The Regulators commonly allow dispensation from use of casing rams as long as a cross-over stand is made available on the rig floor, suitable to stab into the casing and lower across the BOP stack so that pipe rams can be used. This type of short term provision should be addressed in this section.

There are also cases where complete loss of returns is encountered and it is impossible to get returns. Operational progress is made during drilling, or when running casing, by simply pumping water down the hole. This is not "underbalanced drilling", but especially in a land based operation where maybe 30 water trucks are needed to keep up with the losses, it is hard to call the fluid column a "tested barrier." Any water delivery interruption results in one barrier, the BOP stack.

> The PWG has considered CAPP's suggested change to subsection 63(2) and revised the regulation as suggested. Subsection 63(2) now reads:
>
> "After setting the surface casing, every operator shall ensure that during all well operations, there are at least two independent and tested well barriers in place except when working in unperforated cased hole that has been pressure tested."
>
> The PWG recognizes that there may be exceptions to the "two barrier" rule and some of these have already been covered in the regulations through the use of wording such as "After setting the surface casing" in subsection 63(2) and "…except when drilling underbalanced…" in subsection 63(4). However, the two barrier concept is sound in the majority of situations and the regulation has been written to that effect. Where it may not be possible to maintain two barriers, the CSO has the

ability under the Act to grant an equivalency or exemption to the regulation and it is not necessary to explicitly note this in the regulation.

Lastly, the PWG notes that guidance notes will provide further clarification on what constitutes a barrier and CAPP's comments will be considered when discussing the concept of barriers.

Section 63. (3): We suggest inserting the word "or replace" after "restore". If a barrier fails, Operators will need the option to change the type of barrier.

As suggested by CAPP, the words "or replace" have been added after restore.

Section 63. (4): Consider revising this paragraph to read as follows: "During drilling, completion and work over operations, a fluid column can be considered a barrier if it can be monitored and maintained in position." Fluid column barriers are frequently not available during completions and workovers (i.e. not just while under-balanced drilling). This proposed change is more goal oriented.

Also during completion operations on High Pressure-High Temperature (HPHT) wells, it is often not practical to use kill weight packer or completion fluid. If a HPHT well is completed with kill weight annular fluid, any leak into the annulus from the wellbore could result in tubing collapse. This risk is mitigated by using a non-kill weight packer fluid. The two barriers that are in place during completion operations are typically the unperforated (and pressure tested) casing and the rig BOP's.

To address some of CAPP's concerns, the words "and completion" have been removed from subsection 63(4).

The PWG also reiterates its comments under subsection 63(2).

Consider adding a section 63. (5): worded as follows: "The complete BOP stack, consisting of all required rams and annular, shall be considered one barrier, unless an additional element and totally independent operating system is provided. An additional flow control device, or BOP element, functioned by an independent operating control system, is considered a second barrier, assuming it is designed, configured and function tested to seal the wellbore in the event the primary BOP elements become ineffective."

The PWG agrees that the complete BOP stack is considered to be only one barrier but it does not feel that this needs to be stated in the regulations. CAPP's comment regarding a 2nd independently operating system is noted and such a concept would be appropriate for discussion in the guidance notes.

Section 64: Consider changing the wording: "every operator shall ensure that drilling and well control equipment is designed, operated, installed, and maintained in accordance with good oilfield practices, and in accordance with all relevant American Petroleum Institute publications, as amended from time to time" to "Every operator shall ensure that drilling and well control equipment is designed, operated, installed, and maintained in accordance with good oilfield practices, and in accordance with all relevant American Petroleum Institute publications as amended from time to time or other recognized industry standards acceptable to the Board, where the operator demonstrates that these provide an equal or better level of protection."

We also suggest a specific list of the "relevant" API publications should be referenced in this section.

> The PWG notes that section 64 has been revised as follows:
>
> "Every operator shall ensure that drilling and well control equipment is designed, operated, installed, and maintained in accordance with good oilfield practices."
>
> This wording allows the operator the most flexibility in demonstrating that it has appropriate well control equipment and plans. Details on what constitutes good oilfield practice will be discussed in the guidance notes, including what specifications and standards the Boards will be using in their assessment of an operators well control equipment and methodologies.
>
> Lastly, although no longer relevant because of the change in wording to section 64, the PWG notes that the CSO has the ability under the Act to grant an equivalency or exemption to a regulation and it is not necessary to explicitly note this in the regulation.

Additional General comments on Well Control Requirements:

The general nature of "goals" may over time lead to significant variation in well control equipment and rig architecture that could impede the free movement of rigs between operators. Dropping the specific prescriptive well control requirements in the regulations is expected to cause major operators to fall back to in-house standards; this may lead to customized rigs. Small operators may request simpler cheaper rigs. The economic advantages of fast and cost effective movement of rigs between operators could therefore be compromised.

> The PWG notes CAPP's concern; however, the PWG is of the view that this not a likely scenario. Appropriate well control will continue to be a priority for the Boards and there will continue to be a minimum prescriptive standard that would be expected from operators. This will be accomplished by stating in guidance notes what equipment would be appropriate for an operator to use to satisfy the intent of the regulation.

Industry recognized standards such as API and IRP publications will continue to be used by the Boards in their assessments of an operators' well control equipment and methodologies.

Section 2: Casing

Section 76 (2): Consider deleting the wording in this section which states "An operator shall select any casing to be installed in a well on the basis of the performance properties listed in the Performance Properties of Casing, Tubing, and Drill Pipe, API Bul 5C2, issued by the American Petroleum Institute." The rational for deletion is that API 5C2 addresses limited types of connections and arguably mostly dated connections. Limiting the design to API connections makes it impossible to meet the load case design requirements described elsewhere in this specification for many of the wells designed today.

In current oil industry drilling practice, an increasing portion of the tubular products purchased and used are 'proprietary' non-API products in terms of materials, and/or dimensions and/or connections. These tubular products are essential to industry operations and we have no reason to suspect the manufacturer's published performance properties are any less reliable than those of API 5C2.

The performance properties published by API for products produced to API tubular manufacturing guidelines are not universally accepted. In order to improve reliability of well designs some operators have developed 'alternate' performance predictions for use in design, as one example, leak resistance for API connections has been substantially de-rated from the burst rating published by API.

> The PWG notes that the regulation says "must meet or exceed". The intent of this section is not to limit the design options to only API connections – in fact, many proprietary non-API connections are accepted for use. Operators are expected to ensure that appropriate and reliable tubulars and connectors are used with performance properties that meet or exceed the design requirements. The PWG also notes the reference to Bulletin 5C2 is also in the current Drilling Regulations.

Section 77: This section does not provide, nor reference any standard for casing design methodology and/or safety factors (e.g. safety factors, design assumptions, consideration of axial tension on collapse, etc). Base standards (similar to those in place currently) should be replaced, with the addition that alternate methods of casing design that provide equal or better protection are acceptable. This would allow major operators with sophisticated casing design methodology to advance their approach, but also ensure the smaller independent operator has a satisfactory casing program.

> Details related to casing design, including minimum standards, will be discussed in the guidance notes.

Section 77(2) (referred to as 77.2 as CAPP): We also disagree with the use of words "minimum design factors" in this section. This will require the regulators to establish and impose numbers for what they consider acceptable minimum design factors, which basically precludes use of alternative design philosophy such as LRFD design. The following rewording is suggested –"The casing shall be designed to withstand maximum expected loads occurring during installation, drilling and production activities. The casing design must also account for variations in pipe properties, the uncertainty of potential maximum loads, and the risks associated with casing failure."

> The PWG has considered CAPP's comment and subsection 77(2) has been revised as follows:
>
> "The casing shall be designed to withstand maximum expected loads occurring during installation, drilling and production activities."
>
> Design details will be discussed in the guidance notes.

Section 77(3) (referred to as 77.3 by CAPP): We suggest removing the phrase "but need not be limited to" as we feel it adds nothing of value to the sentence. If it is felt that something is needed, state "The operator's design must consider the suitability of the casing for the service application, including type of well."

> In accordance with CAPP's suggestion, the phrase "but need not be limited to" has been removed from subsection 77(3).

Section 78: We feel the word "should" should not be in a regulation. If the Regulators believe "should" is the right word, then this statement should be dropped from the regulations, and considered for possible inclusion in "guidance notes".

In addition we feel the requirements around casing setting depth are extremely vague. In a region like Atlantic Canada where there is limited knowledge of the formations to be encountered and their properties, this may cause a wide discrepancy between various operators and regulators and result in highly subjective decisions. Without both data and a design methodology, an empirically based requirement (such as the current article 70 in the Canada Oil & Gas Drilling Regulations), with the provision to alter the requirements based upon geological information and technical analysis, would be the best solution.

It is very beneficial for industry to have the flexibility to have "control" on the methodology used for casing design and the "level" of risk accepted (i.e. design factor) in the design. However, the acceptance criteria/process for the casing designs needs to be agreed in advance. Due to the long lead nature of these items Operators need to have assurance that the premise upon which casing strings are designed and tubulars are procured will not be rejected at a "later" date. The degree of casing wear which the designs need to accommodate should be specified or left entirely to the Operators discretion. It may be appropriate for the regulation to state that the ADW requires a discussion of how the shoe setting depths have been selected, and how this setting depth addresses the issue of providing suitable kick margin, formation evaluation requirements, and future production scenarios.

In accordance with CAPP's suggestion, the word "should" has been replaced with "shall." Note that the word "carefully" has also been removed. Also note that the words "and production" have been added to paragraph 78(c).

The PWG notes CAPP's comment regarding casing setting depths and other details. These issues are best discussed in the guidance notes as compared to the regulations.

Section 78. (d): Consider revising the wording of this section to read: "Adequate kick tolerance and safe, constant bottom hole pressure well control operations." "Kick margin" has different meanings to different operators. The suggested change would make the statement more goal oriented.

In accordance with CAPP's suggestion, paragraph 78(d) has been revised to read: "Adequate kick tolerance and safe, constant bottom hole pressure well control operations."

Subsection 2: (a) Production Tubing

Section 79. (a): Consider revising the wording of this section to read: "Every operator shall ensure that the tubing in a well is designed to provide for the efficient production and injection of well fluids." There is no need of referencing artificial lift equipment.

The PWG does not see the need to delete the reference to artificial lift equipment. The regulation is written such that artificial lift need only be considered if it adds value.

Section 79. (b): Consider rewording this paragraph to read: "To withstand loads that may result from installation, and operational loads due to pressure and temperature differentials."

The PWG is of the view that the existing wording is appropriate and is inclusive of CAPP's comment.

Subsection 2: (b) Cementation

Section 80. : Cementing into the next casing string will be an issue for subsurface wells where there is no means to bleed off trapped pressure.

The current wording does not require cementing into the previous casing string, except in the case of the surface casing, which is considered good practice. The PWG also notes that the CCO or CSO have the ability under the Act to grant an equivalency or exemption to a regulation and it is not necessary to explicitly highlight all exceptions in the regulations.

Section 80. (1): Consider replacing the phrase "shall achieve the following", with, "shall have the following objectives." The word "achieve" would force operators to verify conclusively, which would be non-value adding and costly at best, or impossible at worse.

This section should also address the inhibition of the fluid spacers left behind casing.

As suggested by CAPP, the words "shall achieve the following" have been replaced with "shall have the following objectives." The PWG also notes that it is of the view that inhibition of fluid spacers is covered in “retard corrosion of casing”

Section 80. (2): Consider revising the wording to read: “Every operator shall ensure that the conductor barrel, conductor pipe, permafrost casing and surface casing are cemented in a manner to provide adequate structural support for the casing, retard corrosion and prevent movement of formation fluids in the annuli.” Where applicable, long term protection of potable water zones is a primary concern. These goals are typically achieved by cementing each string full length. Alternate designs must achieve the same benefits as full length cementing if they are to be proposed in the ADW. Full length cementing provides an indication that cement was, or was not, placed across the entire casing length; alternate procedures must provide suitable indicators, or provide the rationale to demonstrate that the objectives of corrosion protection, providing casing support, and preventing annular fluid movement have been successful.

The PWG is of the view that the current requirement to cement full length would meet the objectives suggested by CAPP. In unusual situations, the PWG notes that the CCO or CSO have the ability under the Act to grant an equivalency or exemption to a regulation.

The PWG also notes that some of the details suggested by CAPP would be appropriate for inclusion in the guidance notes.

Section 80. (3) (a): Consider replacing the phrase with, "intermediate casing, the cement will rise to a minimum of 300m above the intermediate casing shoe or 60m above the shallowest hydrocarbon bearing zone.” This makes the statement more goal oriented.

The reasons for the requested wording change include:

(1) The permafrost is isolated by the surface casing not by the intermediate casing.

(2) In production wells, the intermediate casing will also be the production casing (followed by a production liner).
- Production casing integrity is better assured by avoiding stage cementing tools in this string.
- Production casing integrity is better assured by using an un-cemented annulus to isolate and protect the production casing from the loading - strain on the surface casing caused by permafrost thaw consolidation.
- Production casing integrity is better assured by using an insulating gelled fluid medium in the annulus between the intermediate/production casing and the surface casing instead of cement. This will reduce permafrost thaw consolidation loading and reduce total strain on the well-bore column.

(3) Not cementing the intermediate-production casing into the surface casing shoe will avoid creating 'a pressure vessel cavity' in the surface casing annulus. This avoids creating an incremental burst load case (surface casing) and collapse load case (intermediate-production), the magnitude of such incremental loads are hard to predict and therefore hard to design for.

(4) Not cementing the intermediate-production casing into the surface casing shoe avoids a high risk annular pressure management operation. Temperature effects from well start-up or shutdown cycles causes major pressure fluctuations in the limited volume annulus. Vent / bleed- off pressure management operations can be complicated by hydrate conditions in the annulus and resulting loss of reliability of pressure measurement and bleed systems (reference recent Alaska incident).

(5) Not cementing the intermediate casing into the surface casing shoe allows the possibility of annular injection disposal.

> The PWG has considered CAPP’s suggestions on subsection 80(3) and has revised subsection 80(3) as follows:
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> “(3) Every operator shall ensure that in the case of:
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> (a) surface casing where permafrost exists, the casing shall be set to a depth of 150 m below the base of the permafrost;
>
> (b) intermediate casing, the cement will rise to a minimum of 300m above the intermediate casing shoe or 60m above the shallowest hydrocarbon bearing zone; and
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> (c) production casing, oil, gas, or water zones shall be isolated from one another and the other casing annuli by either setting cement in the annulus to a minimum of 60 m above and 30 m below the zone, or other suitable means to provide equal or better zonal isolation.”

Section 80. (3) (b): Consider replacing the phrase in this section with “production casing, oil, gas, or water zones shall be isolated from one another and the other casing annuli by either setting cement in the annulus to a minimum of 60 m above and 30 m below the zone, or other suitable means to provide equal or better zonal isolation."

See previous comment

Subsection 2: (c) Liners

Section 81. : Consider replacing the phrase in this section with "Every liner intended to function as a barrier shall be adequately cemented." This makes the statement more goal oriented. Industry does not always cement liners full length. Rather we often add liner lap length to allow us to leave a gap, which we consider to be a best practice. Also, Operators need the option of using slotted liners or screens, or intentionally not cementing liners in reservoir intervals, to optimize completions.

Mechanical success of the liner cement job should be sufficient evidence of acceptable isolation. The requirement for cement bond/ cement evaluation logs should not be introduced in the subsequent guidelines.

The PWG has not made the suggested change. The PWG recognizes that slotted liners or screens would not be cemented but as a general practice, liners should be cemented for their full length. Again, the PWG also notes that the CCO or CSO have the ability under the Act to grant an equivalency or exemption for a regulation and if a casing and cementing program included slotted liners or screens, this case would be considered appropriately by the Board.

Regarding the comment on a liner acting as a barrier, the PWG notes that a liner or any casing, once perforated or its integrity has been otherwise lost, would not be considered a barrier.

Subsection 2: (d) Waiting on Cement time

Section 82: We feel that this is a prescriptive statement, and is considered a best practice by most operators. We suggest adding the "goal" of the prescription (e.g. "undisturbed cement sheath with sufficient bonding to formation and casing to provide the necessary pressure and structural integrity") and we recommend the following rewording:

"After cementation of any casing and before resumption of drilling, every operator shall ensure that the time interval while waiting for cement to harden is:

• No less than 12 hours; or

• Confirmation that the cement has the compressive strength of at least 3.5MPA as determined by lab testing; or

• Alternate mechanical means."

The specification of an arbitrary WOC time is counter to the spirit of Goal Oriented Regulation. The section should be amended to specify a minimum performance property (i.e. compressive strength).

> The PWG has not made the suggested change and notes the following:
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> a) The PWG is of the view that the suggested wording change by CAPP is not substantively different than the current proposed wording.
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> b) The PWG is not clear on what CAPP means by “alternate mechanical means.”
>
> c) The CCO or CSO have the ability under the Act to grant an equivalency or exemption for a regulation if warranted.
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> d) The PWG also wishes to clarify that prescription is not “counter to the spirit of goal oriented regulation.” As the PWG has stated previously, goal oriented means a blend of prescription and performance based regulation. Section 82 is an area where the PWG felt prescription was the appropriate way to go. Having said that, the regulation has also been written to provide flexibility regarding the 12 hour wait time if the Operator can demonstrate that a minimum compressive strength of 3,500 kPa has been obtained.

Subsection 2: (e) Case Pressure Testing

Section 83: There is no reference to the issues associated with permafrost. Without limiting the Goal Oriented approach, this issue should be identified with wording such as:

“In Arctic regions, unless permafrost is absent or is present in consolidated formations, the operator shall minimize, to the greatest extent practicable, any deterioration of the ground surface due to thermal disturbance of the permafrost.”

> The PWG notes CAPP’s comment and is of the view that issues pertaining to permafrost are addressed in the general goals iterated in section 75.

Section 83. (1): Consider replacing the phrase with, "every operator shall pressure test surface and intermediate casing to 70% of the internal yield pressure, or the maximum calculated surface pressure, whichever is the lesser," with, “After running casing and cementing and prior to resuming any drilling or undertaking any down-hole operations every operator shall pressure test surface, intermediate and production casing to verify the required, full life, design load integrity.” This makes the statement goal oriented and probably addresses the author’s intent. The 70% criteria are not supported by study or analysis. Further, "guidance notes" would need to prescribe the basis and methodology for determining the, "maximum calculated surface pressure."

> The PWG notes CAPP’s comments regarding subsections 83(1) and (2); however, it has not made the suggested changes to these sections and notes the following:

a) Similar to section 82, the PWG concluded that prescriptive elements were suited for these sections and the numbers used would be appropriate in the majority of situations. Having said that, the proposed wording is less prescriptive than that used in the current Drilling Regulations, so greater flexibility in meeting the intent of the regulation is provided to the Operator.

b) Issues or concerns with pressure testing which do not fit the majority of circumstances, will be dealt with on an operational case-by-case basis and the Boards note that the CCO or CSO have the ability under the Act to grant an equivalency or exemption for a regulation if warranted.

c) Issues relating to casing pressure testing all tie back to the requirement for appropriate casing design.

d) Guidance notes will provide additional details related to casing pressure testing.

Section 83. (2): Consider replacing the phrase, "Every operator shall ensure the entire production casing string is pressure tested in a manner to provide differential burst pressure at any point in the wellbore equal to or greater than it would experience if the maximum formation pressure, less a gas gradient, was applied at surface. Assuming the density of drilling fluids, completion fluids, and packer fluids will vary, the pressure testing schedule and pressure test values shall be appropriate to ensure the entire casing string has been tested to meet the maximum conditions that it could become exposed to in the next phase of operations."

We also feel that the timing requirement for production casing test can be an issue and the manner in which "maximum calculated surface pressure" is determined, needs to be defined.

The wording in this section requires test pressure at surface to equal maximum calculated surface pressure that could be delivered from downhole formations. While this makes sense for testing the casing right at surface, assuming there is still drilling mud in the wellbore while pressure testing, all the casing below surface elevation often becomes exposed to a greater differential burst pressure than it could ever experience by formation generated pressured events. This leads to the possibility that the casing has to be designed to meet the conditions of the pressure test, rather than be designed for the pressure limits that could be obtained by formation generated pressures. Casing designed to meet artificial pressure testing conditions, may not be designed to provide the greatest margin of safety for the real well conditions. Example, using high strength casing to meet pressure testing requirements, may not provide optimum resistance against H_2S embrittlement.

See the PWG's response under subsection 83(1).

<u>Section 3: Testing of Well Control Equipment</u>

Section 90. (1): We suggest a frequency of pressure testing and function testing of BOPs should be specified.

> The PWG notes that subsection 90(1) has been revised as follows:
>
> "Testing of well control equipment shall be conducted as per the testing and maintenance requirements for surface and subsurface BOP stacks and well control equipment stated in the well approval granted under section xx." (PWG note: that is, approval issued by the Board)
>
> Information related to frequency of pressure testing and function testing will need to be submitted by an operator as part of its well approval. The revised wording provides the most flexibility to an operator in outlining its case for what it considers to be appropriate pressure testing and function testing. The Boards will assess the sufficiency of this testing with reference to industry recognized standards such as API and IRP publications. The guidance notes will provide details on what the Boards will expect as well as minimum standards.

Section 90. (2): Pressure control equipment associated with coil tubing, slickline and wireline operations shall be pressure tested upon installation and as appropriate, to ensure the continued safe operation of the equipment. If there is potential for hydrate formation, consideration shall be made for hydrate inhibition (e.g., use glycol during pressure testing of surface equipment).

The manner in which "maximum anticipated surface pressure" (ref: clause 18.3.2.3 of API RP 53) is determined should be defined. Clause 18.3.2.3 of API RP 53 states that annular preventers should be pressure tested to 70% of their rated pressure. We believe that 50% of the rated pressure is sufficient. The Pressure testing frequency stipulated in 18.3.3 of API RP 53 should be used as a guide (ie industry needs flexibility on the "not to exceed 21 days" requirement). Section 18.10.1 of API RP 53 outlines requirements for cleaning, inspecting and testing BOP components after each well. This will not be feasible during BOP "Hopping" operations.

> As a result of the change to subsection 90(1), the specific issues raised by CAPP will now be captured during the approval process. For example, in situations where the operator is of the view that testing frequencies contained in API 53 are not appropriate, the operator may then outline why it considers an appropriate testing frequency to be sufficient. The Board would consider the information submitted prior to making a decision on testing frequencies. Similarly, if hydrates are an issue, then this can be considered during the approval process. Again, the guidance notes will provide details on potential issues to consider with respect to subsection 90(2).

Section 4: Evaluation of Wells, Pools and Fields

Section 95. (1): Consider rewording this paragraph as follows: **"**Every operator shall obtain from each well sufficient data to ensure that a comprehensive geological and reservoir evaluation can be made." Not every well drilled (exploration, appraisal or production well) needs to conduct or collect all of the following: cutting and fluid samples, logs, conventional cores, side wall cores, pressure measurements and formation flow and well tests, analyses and surveys.

> The suggested change has not been made. The intent of subsection 95(1) is to act as a general introductory clause with the details of such data collection being required provided in section 95.1. If the gathering of a certain type of data is not required or necessary, then not collecting that data would be "sufficient". The PWG also notes that the current Drilling Regulations (s. 186 COGOA and s. 160 Accord Acts) also list some data types and this hasn't created any problems to date.

The regulations should also include a clear definition of what constitutes a "well." The definition should take into account multilaterals as well as sidetracks. Note that in the Interpretation section of the draft D&P Regulations, the noun "well" is not defined; however, "wellbore" is. Industry will need clarity as to whether a relief well (i.e., a well drilled as an emergency response to extinguish a blow out) would be required to collect samples, and run logs. If this is meant to replace both the current Regulations and the Guidelines it seems to imply that the responsibility is passed to the operator to decide what is sufficient and comprehensive. On the other hand, if the Regulators plan is that this be used in conjunction with the existing guidelines, we don't see that it helps formation evaluation when the current Guidelines are so specific.

> What constitutes a well is defined in the Act (section 2 COGOA; Section 135 Accord Acts). Thus, it is not necessary, or legally appropriate, to restate the definition in the Regulations. Relief wells would be drilled under exceptional circumstances and therefore, would not be subject to the data collection requirements contained in section 95(1).
>
> Regarding the statement on what is sufficient and comprehensive, although it will be up to the operator to outline its case for what it believes to be a sufficient and comprehensive program, it will ultimately up to the Board to approve the data acquisition program.
>
> Regarding the comment on guidelines, it will be up to each Board to decide which Guidelines will continue to be utilized or amended and what new guidance notes will need to be developed. Further, the PWG notes that it will be developing guidance notes for the goal oriented DP Regs.

Section 95.1. (1) (2): The goal that the operator should be achieving should be clearly indicated. The current wording implies that satisfying the Board is the goal.

The goal to be achieved is stated in section 95(1); that “a program that provides for a comprehensive geologic and reservoir evaluation.” The program would be approved by the Board if it was of the view that the program accomplished this. To provide clarity and to tie 95.1 (1) back to 95(1), the PWG has added “that satisfies the requirements of section 95(1).” at the end of 95.1(1).

95.1(2) Consider rewording this paragraph as follows: “The Board shall approve the well data acquisition program where the Board is satisfied that the program provides for a comprehensive geologic and reservoir evaluation.”

We are unclear as to what “*does not cause waste*” refers to. If it is lost fluids during flow testing then this wording is appropriate.

The suggested change has not been made. Waste is used here in the context of appropriate management of the hydrocarbon resource. Waste is defined in the Act (subsection 18(2), COGOA and subsection 154(2) Accord Acts) and must be considered as part of any operation or activity. Guidance notes will further discuss the concept of waste.

Section 95.1. (3): Consider rewording this paragraph as follows: “Every operator shall, follow a field data acquisition program described in the field Development Plan approved by the Board. Notification of deviations from the field data acquisition program must be submitted to the Board on a well by well basis.”

The PWG does not agree. The level of detail required is too high to be captured in the Development Plan (DP) and the detail is usually not sufficiently developed at the time the DP is submitted.

It is also not clear to us why it is necessary to put this together when it will be outdated very shortly after development wells start to be drilled.

It is required to ensure that an overall field evaluation plan has been developed before the first well is drilled and some opportunity is lost. It is anticipated that it will allow for evaluation requirements to evolve as field development progresses.

Also, to provide clarity, similar to revisions made to section 95.1(1), the words, “that satisfies the requirements of section 95(2).” have been added at the end of 95.1(3).

Section 95.1(4): Consider removing this section as the Data Acquisition program should have an expiry (such as the current 3 years) so that the program can be updated to reflect current data acquisition requirements.

No change necessary. A modified data acquisition program can be submitted for approval whenever appropriate; there is no need to set a prescriptive timeframe.

Section 95.2 (a) Consider rewording this paragraph as follows: "Where part of the well or field data acquisition program referred to in **section 95.1** cannot be achieved, every operator shall immediately notify a Conservation Officer of the deficiency."

Section 95.2 (b) We suggest rewording this subsection as follows: "Submit a program to the Board, for approval, requesting dispensation from acquiring the data, and/or provide details as to how alternative information may be acquired." We cannot necessarily obtain the same information if it was not acquired at the first attempt. Rewording this will be very beneficial as it will allow the operator to take action if necessary, and then to negotiate with the Board to acquire a suitable alternative data set.

The modifications to these paragraphs would take into account the fact that while data acquisition deferment can occur because of operational difficulties, there may be situations (based upon drilled well results) that will result in the Operator not continuing with follow-up or appraisal well drilling resulting in no activities that could allow for data to be deferred (or subsequently obtained).

> The PWG has revised the regulations in accordance with CAPP's suggested changes. Section 95.2 (a) and (b) now read:
>
> 95.2. Where part of the well or field data acquisition program referred to in section 95.1 cannot be achieved, every operator shall:
>
> (a) immediately notify a Conservation Officer of the deficiency; and
>
> (b) submit the procedures for approval by the Board, to be used to obtain the information that would have been obtained from the part of the well or field data acquisition program that was not achieved.
>
> The PWG notes that it is not necessary to include the suggested clause regarding dispensation, as the Board already has the authority to grant and exemption from the regulation under the Act.

Subsection 4: (a) Drill Cuttings and Gas Content of Drilling Fluid

Section 96.1. Consider rewording this paragraph as follows: "Every operator shall ensure that cores and cuttings samples taken pursuant to Section 95 are handled, marked, described and analyzed."

> The suggested change has not been made. The guidance notes will provide additional guidance as to what good oilfield practice is.

We also note that volume and nature of NEB sample requirements are not specified – presumably this would be addressed in the "Approval to Drill a Well" (ADW).

> The sample requirements would be specified in the guidance notes.

Subsection 4: (b) Formation Evaluation Logging

Section 96.2. Consider rewording this paragraph as follows: "Every operator shall ensure that sufficient logs are run to allow for determination of lithology, net pay, porosity, fluid saturation, pool pressure and fluid contents for all prospective reservoir units."

The wording in this section appears to force operators to measure pressures and determine fluid contacts in every potential zone below the surface casing, with no regard to whether the operator thinks they have a chance of being commercial or not.

> The PWG does not agree. Some of these parameters (like pressure) cannot be determined in some zones or horizons so they would not be expected, but these parameters should be obtained where they can. It is required that the wells are fully logged so that decisions can be made about whether zones are a prospective reservoir or not.

Section 96.3. Consider rewording this paragraph as follows: "Every operator shall take formation evaluation logs in the uphole non-reservoir interval, if needed for the purposed for well evaluation."

We would like clarification on who will decide if surface casing hole section logs are, "needed for the purposes of well evaluation."

> The PWG does not agree. The case outlined in CAPP's suggested change is already covered. Section 96.3 specifically covers the surface casing hole that is not addressed in section 96.2.
>
> Regarding the decision to log surface casing hole, it will be up to the operator to present its case as why it is of the view that logging is or is not necessary. The Board will then decide following discussion with the operator.

Subsection 4: (c) Cased Hole Logging

Section 96.4. We are unclear as to who will decide if a cased hole log, "would significantly contribute to the evaluation of the pool in which the well is located?" If left to the Operator, then these two statements are goal oriented, but unclear. If left to the regulator, we will need to see the "guidance notes" prescribing how the evaluations and decisions must be made.

> Again, it will be up to the Operator to present its case as why it is of the view that cased hole logging would or would not "significantly contribute" to pool evaluation and the Board would then decide following discussion with the Operator. Guidance notes will provide clarification as to when the Board thinks that cased hole logging would be required.

The term "pool" should also be defined. The concept for refining pool designations over life of a field as new information is available should be acknowledged in regulations.

Pool is defined in the Act (section 2 COGOA and Accord Acts). Pool designations are addressed in the Reporting section of the DP Regs.

Subsection 4: (d) Formation Pressure Measurements, Formation Flow Testing and Well Testing

We understand this section is still being written and will be of particular interest to industry. Well testing requirements are an area that we would like to see changes to the current guidelines and when proposed amendments to this section are drafted, we would appreciate an opportunity to comment.

Since release of the draft goal oriented DP Regs for comment, the sections pertaining to formation flow testing were finalized and are currently in the process of being brought into force in the Accord Act Drilling Regulations. Following is the wording that will form part of the DP Regs:

XX. Every operator shall ensure that every formation in a well is tested and sampled in a manner to obtain reservoir pressure data and fluid samples from the formation, if there is an indication that such data or samples would contribute substantially to the geological and reservoir evaluation.

Formation Flow Test

XX. (1) An operator may conduct a formation flow test on a well drilled on a geological feature if, prior to conducting that test, the operator

(*a*) submits to the Board a detailed testing program; and

(*b*) obtains the approval of the Board to conduct the test.

(2) The Board shall approve a formation flow test if it determines that the test will be conducted safely and in accordance with good oilfield practices and that the test will enable the operator to

(*a*) obtain data on the deliverability or productivity of the well;

(*b*) establish the characteristics of the reservoir; and

(*c*) obtain representative samples of the formation fluids.

(3) The Board may require that the operator conduct a formation flow test on a well drilled on a geological feature, other than the first well, if there is an indication that such a test would contribute substantially to the geological and reservoir evaluation.

Subsection 4: (e) Fluid Samples

Section 96.10(2) (c): Industry feels there is no need to prescribe frequency such as “as least every 12 months.” Therefore we suggest replacing it with the following “as necessary for field reservoir management.”

> The PWG has revised the regulations in accordance with CAPP’s suggestion. Frequency of sampling would be discussed in the guidance notes.

We also suggest removing **section 96.10. (4)** “Every operator shall ensure that every fluid sample is taken and analyzed in accordance with good oilfield practices.”

> The suggested change has not been made. The guidance notes will provide additional guidance as to what good oilfield practices are.

Subsection 4: (f) Pool Pressure Surveys or Measurements

Section 96.12. (1): We assume that the statement “Every operator shall conduct an annual pool pressure survey to determine the static pressure in a pool in accordance with an approved field data acquisition program.” does not mean a well intervention to measure static pressure is required every year in every pool and that estimation by calculation is acceptable.

> The PWG confirms that CAPP’s assumption is correct.

Subsection 4: (g) Submissions of Samples and Data

Section 96.14: Consider rewording this paragraph as follows: “Every operator shall ensure that after any samples necessary for the analysis referred to in **section 96.1**, or for other studies deemed necessary by the operator, have been removed from the core, the remaining core or a longitudinal slab of the core that is not less than one half of the cross-sectional area of the core is submitted to the Chief Conservation Officer.”

> The regulation will be revised as follows:
>
> “Every operator shall ensure that after any samples necessary for the analysis referred to in section 96.1, *or for other studies approved by the Board*, have been removed from the core, the remaining core or a longitudinal slab of the core that is not less than one half of the cross-sectional area of the core is submitted to the Chief Conservation Officer.”

Given that there are never enough cores especially in a situation where extensive rock mechanics testing of a particular interval, including fluid sensitivities for sand control completions, is required, the regulations should be less prescriptive in describing the amount of core to be submitted to the Chief Conservation Officer.

> The PWG is of the view that this section allows for sufficient flexibility in use of core for analysis.

Section 5: Testing and Reporting Requirements for Safety Systems

Section 123: We wonder how broad is the definition of the safety system may be. Do the dump valves on the mud tanks make it into this category for example (i.e. they are a barrier to an environmental release)?

> In reference to this comment and following comments by CAPP, the PWG notes that it has revised the definition of safety system to include the concept of environmental protection. Further, in reference to CAPP's comment on what installations require safety and environmental protection systems, the PWG confirms that all installations will require the information outlined in section 123, albeit the scope of such information would vary in accordance with the complexity of an installation and the potential for impacts to safety and the environment.
>
> The proposed definition for safety and environmental protection system is as follows:
>
> "safety and environmental protection system means a system installed on an installation that is capable of detecting hazardous conditions or abnormal operating conditions on the installation that could result in adverse effects on persons or the environment, and is designed so that, depending on the condition, the system is able to safely shut down the installation or a portion thereof."
>
> Further, the PWG notes that the Draft DP Regs will be revised to indicate that the requirement for testing and maintenance of safety and environmental protection systems will apply to all installations, not just production installations, as the current draft implies.

Section 123. (1) Consider rewording this paragraph as follows: "Every operator shall submit to the Board, as part of an application for an operations authorization, a maintenance, inspection and testing program for its facility safety systems."

> The PWG has considered CAPP's suggestion and has revised this subsection as follows:
>
> "**123. (1)** Every operator shall submit to the Board, as part of an application for an operations authorization, a maintenance, inspection and testing program for its facility safety and environmental protection systems."

Section 123. (2) Consider rewording this section as follows: "Every operator shall ensure that the program referred to in subsection (1) results in an availability that meets the performance standards (quantitative risk assessments, safety analysis etc.) as defined by the operator for these systems."

The PWG has not made the suggested revision as it is of the view that “reliability” is a key concept, and not just, “availability”. A system could be available, but not functioning as per specification. Further, the goal of “high reliability” is a more appropriate goal than “performance standards as defined by the operator”. Having said this, performance standards as defined by the operator would be key in contributing to the concept of high reliability.

The guidance notes will provide additional information on how an operator should be promoting the concept of high reliability in its safety and environmental protection systems and CAPP’s comments will be considered in the development of the guidance notes.

Section 123. (3) Consider rewording this section as follows: “The Safety System Test Program tasks and intervals shall be determined through application of a risk-based methodology, taking into consideration:

(a) Safety system design, specification and equipment reliability;
(b) Expected operating conditions;
(c) Assessed consequences of equipment failure, including secondary effects on other safety related systems;
(d) Provision for adjustment of tasks and intervals based on observed trends in plant specific reliability data; and
(e) Means of accurate reporting to the board in the event of a unsuccessful test, or equipment failure leading to a safety system impairment.

The PWG has considered CAPP’s suggestion and revised this subsection as follows:

“**123. (3)** The program referred to in subsection (1) must consider:

(a) analysis of the testing system as a whole;

(b) if using a risk based methodology, target levels of safety and environmental protection;

(c) the safety and environmental protection system design, specification, and equipment reliability;

(d) operating conditions;

(e) the maintenance program;

(f) the safety and environmental protection system testing frequency;

(g) operating procedures; and

(h) reporting requirements to the Board, in the event of an unsuccessful test of the system or failure of the system, or equipment failure leading to a safety and environmental protection system impairment.”

.

The changes made enable an operator to use a risk based methodology or a more prescriptive methodology. Additional guidance will be provided in the guidance notes. The PWG also notes that CAPP's suggested bullets (c) and (d) will be considered when developing the guidance notes.

Note: As the testing program will be developed using risk based methodology, the associated guidance notes should only contain interpretation and guidance with respect to how the above is achieved and not define prescriptive periods.

The guidance notes will contain guidance on both risk based and prescriptive methodologies.

Note: The definition of "Safety Systems" as it currently exists in the combined Drilling and Production Regulations is:

"safety system" means the system installed on a production installation that is capable of detecting hazardous conditions or abnormal operating conditions on the installation and is designed so that, depending on the condition, the system is able to initiate a safe shutdown of the production installation or a portion of it.

The definition associated with "safety systems" includes a "production installation" but does not include a "drilling installation." Is it the intent of section 123 to only be applicable to a Production installation or should it also include a drilling installation? If the intent is to include drilling installations then this should be made clear within the "safety system" definition. In addition the definition would also have to be modified to account for the differences of the drilling installation. (refer to "production installation" and "drilling installation" definitions within the Drilling and Production Regulations.)

See previous comments regarding safety and environmental protection systems definition.

Assuming that the intent is to include drilling Installations then consideration should be given to the fact that Operators do not always own, and therefore directly control, offshore installations. Examples include offshore drilling rigs or MODU's, which are almost always contracted. This section should clearly define if the intent is to deliver to the regulators a document equivalent to a UK "Safety Case". This would probably be acceptable to industry, as Installation Owners (not Operators) would appropriately be made responsible for producing and maintaining the Safety Case for the installation they own and manage. Further, the large number of UK rigs would become more readily and cost effectively available to East Coast Operators who currently have to work in a highly limited rig market. As in the UK, Canadian regulators would audit an installation against its Safety Case for compliance, and hold the Installation Owner (not the Operator) accountable for fixing deficiencies. Operators would also contractually obligate Installation Owners to comply with the Installation Safety Case, providing further leverage for delivering the intent or goal: a safe, compliant installation.

The PWG notes that the requirements for safety and environmental protection plans in the DP Regs will be modified to facilitate the submission of an HSE Case by an operator, should they choose to do so. However, in the Canadian regulatory context, submission of an HSE Case by an operator will not shift the "duty" from the operator to the installation owner. Although it is likely that the installation owner would develop and implement the HSE Case, it will still be up to the operator to accept it for the proposed work or activity.

<u>Section 6: Measurement</u>

We also wonder if the Measurement Guidelines under the Newfoundland and Labrador and Nova Scotia Offshore Areas Petroleum Production and Conservation Regulations, October 2003 will be revised to reflect a goal oriented approach? Currently the guidelines are very prescriptive.

> It is anticipated that the current guidelines, written in 2003 with CAPP input, will still largely stand. As discussed at the beginning of those guidelines, target accuracies are provided with possible methods of meeting them but the Board's are open to consideration of alternative solutions.

The overall goal of the Measurement section is missing. It should clearly be stated what the purposes of the measurements are for (i.e. royalties, reservoir maintenance, allocation etc) such that the required measurement accuracies and flow system boundaries can be determined.

> The following wording has been added to regulations:
>
> **162.** Purpose of measurement:
>
> (1) To account for all fluids produced and injected.
>
> (2) To enable reservoir management.
>
> (3) For monitoring compliance with the regulations.

Section 163. (a): We suggest revising the wording from "each fluid" to "Oil, Gas and Water." Other items such as chemicals that are injected into the wells should not be required to be measured and reported as part of this regulation.

> The PWG does not agree as it is required that all fluids are tracked.

Flare volumes are sometimes difficult to measure. There should be an allowance for a calculated volume as well as it suggests that fuel gas volumes of less than 500 m3/day need not be measured.

> The PWG recognizes difficulties associated with measurement of flare volumes and where it is not practical to measure as such, these data would not be required. Again, the PWG notes that the CCO or CSO has the authority, under the Act, to grant an exemption from a regulation.
>
> The PWG notes CAPP's comment on flare volumes. Details such as what volumes would be reportable will be discussed in the guidance notes.

Section 163. (a) (iii): the word "used" is unclear – this is probably meant to account for such things as fuel gas and gas lift. We are also unclear as to produced water disposal.

The PWG notes that section 163 has been revised as follows:

163. Subject to Section 164, every operator shall measure and record the rate of flow and the total volume of:

(a) each fluid that is

(i) produced from each well,

(ii) injected into each well; and

(iii) transferred from, flared, disposed of, or used on the installation;

(b) each fluid that enters or leaves a battery, facility, processing plant, or other installation.

Section 163. (b): The term "each fluid" is too vague for a regulation. The types of fluid should be noted.

The PWG does not agree. All fluids should be tracked, though some require lower levels of accuracy which would be captured in the guidelines. Additionally, the guidance notes will provide details on fluids to be tracked.

Consistent with these regulations operators should be permitted to propose a Measurement System that is founded on company and industry standards and best practices. For example, well testing frequencies, designation of pools and zones should be left to the operator to propose.

The Regulations allow for flexibility and the existing Measurement Guidelines encourage discussion of alternatives. To-be-developed guidance notes will provide additional guidance. Final pool designations will remain with the CCO, though usually in consultation with the operator.

Section 164: This section does not make any specific reference to the use of a test separator, which is a big space issue offshore. Wording looks like it leaves the door open to not using test separators in the future.

Use of a test separator would be considered as part of the overall measurement and allocation system developed under section 164(1). If no test separator is proposed, then its normal functions would have to be captured in other ways acceptable to the Board.

Section 164. (1): Using the term "reasonably accurate determination" without defining the determination intent (i.e. royalties, allocation, reservoir maintenance etc) is too vague.

The PWG does not agree. This level of detail is best suited for the guidelines and guidance notes.

Section 164. (1): We suggest removing "on a pool and zone basis." The implication of having to report production or injection on a zone by zone basis is significant.

The PWG does not agree. “On a pool and zone basis” is necessary to avoid waste as referred to in the Act.

Section 164. (5): Consider removing this subsection. Allocating production/injection to individual pools/zones in a commingled multi-layer reservoir is an onerous requirement and would require production logs to be run frequently. The monthly production reporting formats would also be impacted by this requirement.

The PWG does not agree. It is being managed today. Some level of commingled reservoir management will be a requirement of permitting commingled production.

Subsection 6: (a) Testing, Maintenance, and Notification

Section 165(2): The PWG notes that subsection 165(2) has been revised as follows:

“Every operator shall ensure that equipment used to calibrate the flow system is calibrated.”

Details regard calibration standards will be discussed in the guidance notes.

Section 165. (3): We suggest you consider removing this subsection. Subsection (4) adequately describes the actions required in the event of a measurement failure. If the NEB disagrees with complete removal of this section then we request that the following wording changes be made:

“Every operator shall repair or replace forthwith any component impacting the accuracy of the flow system, or enact a contingency plan which will provide the means to obtain the results with a reasonable level of accuracy, until such time that the repair or replacement of the malfunctioned component can take place.”

The proposed wording accounts for the fact that not every component that fails will impact the accuracy or integrity of the metering systems. Also it may not be practical to immediately repair or replace malfunctioning equipment.

The PWG does not agree. As a matter of practice, malfunctioning equipment should be replaced as soon as possible. Additionally, section 165(4) provides adequate flexibility for operators to describe how they are remedying any failure, including a description of alternate data gathering methods.

Section 165. (6) We are unclear as to the intent or goal of this paragraph. It does not appear to fit with either a prescriptive or goal oriented approach but instead seems to provide the regulator the authority to require additional testing without providing the reasons why. This is too broad since it covers all “measurement appliances.”

The PWG notes that subsection 165(6) has been revised as follows:

165. (6) The Board may order that any measuring appliance shall be tested or examined in a manner, on the occasions or at the intervals and by the person, specified by the Board.

The PWG notes that the CCO already has the authority under paragraph 54(e) of the COGOA to order any reasonable tests of examinations. Reasons why these tests would be undertaken would fall within the concept of what is reasonable.

Subsection 6: (b) Transfer Meters

Section 166: This requirement is acceptable providing it replaces the Board's existing requirements. If this assumption is not correct this requirement adds a layer of reporting that does not currently exist and might put industry in the middle of conflicting objectives between the Offshore Boards and the NEB.

The PWG is not clear on what this comment means.

Subsection 6: (c) Metering Records

Section 167: This requirement is acceptable providing it replaces the Board existing requirements.

Section 168: We suggest you consider removing "on a pool and zone basis" from this section.

The PWG does not agree. "On a pool and zone basis" is necessary to avoid waste as referred to in the Act.

Goal Oriented Drilling and Production Regulations – March 2006

Background

For additional information, the reader should refer to the Board's letters, and associated attachments, entitled "Public Comment Period, Development of Goal Oriented Drilling and Production Regulations," dated 11 April 2005, "Comments on the Draft Goal Oriented Drilling and Production Regulations (DP Regs)," dated 20 October 2005, and "Project Working Group Detailed Response to the Canadian Association of Petroleum Producers' (CAPP) Comments on the Draft Goal Oriented Drilling and Production Regulations (DP Regs)," dated March 2006. These documents are available on the Board's web site (www.neb-one.gc.ca) under the buttons "Engaging Canadians"/"Drilling and Production Regulations".

Included in the scope of the goal oriented rewrite of the DP Pegs are the following six topics:

- General Well Control Requirements
- Casing
- Testing of Well Control Equipment
- Evaluation of Wells, Pools, and Fields
- Testing and Reporting Requirements for Safety Systems
- Measurement

All section numbers noted for replacement in the attached goal oriented drafts refer to the numbering scheme within the draft DP Regs, which are currently progressing through the regulatory review process in the federal Department of Justice. Further, for ease of reference, the drafts refer to the draft DP Regs developed under the *Canada Oil and Gas Operations Act* (COGOA) only; therefore, section numbers do not correspond to the draft DP Regs developed under the Offshore Accord Acts[1]. However, as regulations developed under the COGOA and the Offshore Accord Acts mirror one another, the wording that will appear in the DP Regs developed under the COGOA or the Offshore Accord Acts will be very similar, if not, identical. The draft DP Regs developed under the COGOA are available on the Board's web site (www.neb-one.gc.ca) under the buttons "Engaging Canadians"/"Drilling and Production Regulations" on the home page.

Development of accompanying guidance notes will also be part of the goal oriented rewrite of the Drilling and Production

[1] The Canada-Newfoundland Atlantic Accord Implementation Act; the Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act; the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act; and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act.

Regulations and this phase of the project is in beginning stages.

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General Well Control Requirements

(Would replace sections 63-73 of the draft DP Regs)

63. (1) Every operator shall ensure that during all well operations, reliably operating well control equipment is installed, the purpose of which is to:

(a) control kicks;

(b) prevent blow-outs; and

(c) safely achieve all well activities and operations, including drilling, completion, and workover operations.

(2) After setting the surface casing, every operator shall ensure that during all well operations, there are at least two independent and tested well barriers in place except when working in unperforated cased hole that has been pressure tested.

(3) If a barrier fails, no other activities, other than those intended to restore or replace the barrier, shall take place in the well.

(4) During drilling operations, except when drilling under balanced, one of the two barriers to be maintained shall be the drilling fluid column.

64. Every operator shall ensure that drilling and well control equipment is designed, operated, installed, and maintained in accordance with good oilfield practices.

Casing

(Would replace sections 75-89 and 93 of the Draft DP Regs)

General

75. Every operator shall submit to the Board, as part of an application for Approval to Drill a Well, a casing and cementing program, the purpose of which, is to:

(a) properly control formation pressures and fluids;

(b) prevent the direct and indirect release of fluids from any stratum through the well bore;

(c) prevent communication between separate hydrocarbon bearing strata;

(d) protect fresh water aquifers from contamination;

(e) support unconsolidated sediments, protect and isolate all permafrost and hydrate strata; and

(f) provide for the efficient production and injection of well fluids.

Casing Design

76. (1) Every operator shall ensure that any casing used in a well

(a) is new; or

(b) if used, is inspected as per API RP- 5C1, *Recommended Practice for Care and use of Casing and Tubing,* as amended from time to time.

(2) Casing and connections must meet or exceed the minimum performance properties listed in API BUL. 5C2, Performance *properties of Casing, Tubing and Drill Pipes,* as amended from time to time.

77. (1) Every operator shall design the casing to withstand the anticipated stress imposed by tensile, burst, collapse, bending, buckling loads, thermal effects, and combinations thereof.

(2) The casing shall be designed to withstand maximum expected loads occurring during installation, drilling and production activities.

(3) Every operator's design must consider type of well, water depth (for offshore wells), potential for high pressure zones, metallurgical considerations, and the potential for H_2S or CO_2.

78. The shoe setting depth shall be chosen to allow for:

(a) maximum formation fracture gradient;

(b) minimum hole problems;

(c) formation evaluation and production requirements; and

(d) adequate kick tolerance and safe, constant bottom hole pressure well control operations.

Production Tubing

79. Every operator shall ensure that the tubing used in a well is designed

(a) to permit the installation of artificial lift equipment wherever there is reason to believe that artificial lift equipment might be required in order to maintain flow rates and increase ultimate recovery from the pool or field;

(b) to withstand the conditions, forces, and stresses that might have a detrimental effect on the tubing; and

(c) with respect to sour service, to meet National Association of Corrosion Engineers, NACE Standard MR0175-92 Item No. 53024, *Standard Material Requirements, Sulfide Stress Cracking Resistant - Metallic Materials for Oilfield Equipment,* as amended from time to time.

Cementation

80. (1) Cement slurry design and procedure shall have the following objectives:

(a) prevent the movement of formation fluids in the annuli (casing to formation or casing to casing);

(b) provide support for the casing; and

(c) retard corrosion of the casing.

(2) Every operator shall ensure that the conductor casing, permafrost casing, and surface casing are cemented, from the shoe of the casing to the top of the casing.

(3) Every operator shall ensure that in the case of:

(a) surface casing where permafrost exists, the casing shall be set to a depth of 150 m below the base of the permafrost;

(b) intermediate casing, the cement will rise to a minimum of 300m above the intermediate casing shoe or 60m above the shallowest hydrocarbon bearing zone; and

(c) production casing, oil, gas, or water zones shall be isolated from one another and the other casing annuli by either setting cement in the annulus to a minimum of 60 m above and 30 m below the zone, or other suitable means to provide equal or better zonal isolation.

Liners

81. Every liner shall be cemented for its full length.

Waiting on Cement Time

82. After cementation of any casing and before resumption of drilling, every operator shall ensure that the time interval while waiting for cement to harden is in no case less than 6 hours and is less than 12 hours only where the operator determines, by testing representative samples of the cement, that the cement has a minimum compressive strength of at least 3,500 kPa.

Casing Pressure Testing

83. (1) After running casing and cementing and prior to resuming any drilling or undertaking any down-hole operations, every operator shall pressure test surface and intermediate casing to 70% of the minimum internal yield pressure, or to the maximum calculated surface pressure, whichever is the lesser.

(2) Every operator shall pressure test production casing to 100% of the maximum calculated surface pressure.

Testing of Well Control Equipment

(Would Replace Sections 90 - 92 of the Draft DP Regs)

90. (1) Testing of well control equipment shall be conducted as per the testing and maintenance requirements for surface and subsurface BOP stacks and well control equipment stated in the well approval granted under section xx.

(2) Pressure control equipment associated with coil tubing, slickline, and wireline operations shall be pressure tested upon installation and as appropriate, to ensure the continued safe operation of the equipment.

Evaluation of Wells, Pools and Fields

(Would Replace Part V – sections 94-117 of the draft DP Regs)

General

95. (1) Every operator shall obtain from each well sufficient cutting and fluid samples, logs, conventional cores, side wall cores, pressure measurements and formation flow and well tests, analyses and surveys, using good oilfield practice, to ensure that a comprehensive geological and reservoir evaluation can be made.

(2) Every operator shall obtain sufficient pool pressure measurements, fluid samples, cased hole logs and well tests to ensure a comprehensive assessment can be made of the performance of development wells, pool depletion schemes and fields.

95.1. (1) Every operator shall submit to the Board, for approval, a well data acquisition program that satisfies the requirements of section 95(1).

(2) The Board shall approve the well data acquisition program where the Board is satisfied that the program provides for a comprehensive geologic and reservoir evaluation and does not cause waste.

(3) Every operator shall, 90 days prior to initiating development well drilling in a field, submit to the Board, for approval, a field data acquisition program that satisfies the requirements of section 95(2).

(4) The Board shall approve the field data acquisition program where the Board is satisfied that the program provides for a comprehensive assessment of the performance of development wells, pool depletion schemes and fields.

95.2. Where part of the well or field data acquisition program referred to in section 95.1 cannot be achieved, every operator shall:

(a) immediately notify a Conservation Officer of the deficiency; and

(b) submit the procedures for approval by the Board, to be used to obtain the information that would have been obtained from the part of the well or field data acquisition program that was not achieved.

(c) The Board shall approve the procedures if it is satisfied that the proposed procedures provide an equivalent level of information as the part of the well or field data acquisition program that was not achieved.

Drill Cuttings and Gas Content of Drilling Fluid

96. (1) Every operator shall:

(a) determine and record the hydrocarbon gas content of all drilling fluid returning to the surface; and

(b) ensure samples of drill cuttings are collected from those portions of the well set out in the well data acquisition program.

(2) For samples not obtained, every operator shall, in the final well history report, report to the Chief Conservation Officer, the depth intervals along with the reason for not obtaining the samples.

Cores and Cutting Samples

96.1. Every operator shall ensure that cores and cutting samples taken pursuant to Section 95 are handled, marked, described and analysed in accordance with good oilfield practice.

Formation Evaluation Logging

96.2. Every operator shall ensure sufficient logs are run below the surface casing to allow for determination of lithology, net pay, porosity, fluid saturation, pool pressure and fluid contacts.

96.3. Every operator shall take formation evaluation logs in the hole drilled for the surface casing, if needed for the purposes of well evaluation.

Cased Hole Logging

96.4. Every operator shall run a cased hole log on a well if it is technically feasible to do so and the cased hole log would significantly contribute to the evaluation of the pool in which the well is located.

Formation Pressure Measurements, Formation Flow and Well Testing

xx. Every operator shall ensure that every formation in a well is tested and sampled in a manner to obtain reservoir pressure data and fluid samples from the formation, if there is an indication that such data or samples would contribute substantially to the geological and reservoir evaluation.

xx. (1) An operator may conduct a formation flow test on a well drilled on a geological feature if, prior to conducting that test, the operator

(*a*) submits to the Board a detailed testing program; and

(*b*) obtains the approval of the Board to conduct the test.

(2) The Board shall approve a formation flow test if it determines that the test will be conducted safely and in accordance with good oilfield practices and that the test will enable the operator to

(*a*) obtain data on the deliverability or productivity of the well;

(*b*) establish the characteristics of the reservoir; and

(*c*) obtain representative samples of the formation fluids.

(3) The Board may require that the operator conduct a formation flow test on a well drilled on a geological feature, other than the first well, if there is an indication that such a test would contribute substantially to the geological and reservoir evaluation.

Fluid Samples

96.10. (1) Where an operator completes a well in a pool, every operator shall take a representative sample of reservoir fluids from the well where it would contribute to the evaluation of the pool or field in which the pool is located.

(2) Every operator shall obtain and analyze oil, gas and water samples from a sufficient number of wells to determine the composition of:

(a) fluids in the pool,

(b) fluids injected into a pool, and

(c) produced fluids used as fuel, discharged or transferred from a production facility,

as necessary, for field reservoir management.

(3) Every operator shall obtain and analyze samples of oil, gas and water whenever there is reason to believe that the composition of a fluid produced from a pool has changed from that determined in the analysis undertaken pursuant to subsection (2).

(4) Every operator shall ensure that every fluid sample is taken and analyzed in accordance with good oilfield practices.

Pool Pressure Surveys or Measurements

96.11. Before an operator commences production from or injection into a development well, the static pressure of the pool at the completion interval shall be determined and recorded.

96.12. (1) Every operator shall conduct an annual pool pressure survey to determine the static pressure in a pool in accordance with an approved field data acquisition program.

(2) Every operator shall report the results of the survey to the Chief Conservation Officer together with the Annual Production Report.

Submission of Samples and Data

96.13. Every operator shall ensure that all cuttings samples, fluid samples, cores or other materials taken from a well in compliance with these Regulations are:

(a) transported and stored in a manner that prevents any loss or deterioration;

(b) delivered to the Board within 60 days of the well termination date unless analyses are ongoing, in which case they, or the remaining parts, are to be delivered on completion of the analyses; and

(c) stored in durable containers properly labelled for identification.

96.14. Every operator shall ensure that after any samples necessary for the analysis referred to in section 96.1, *or for other studies approved by the Board*, have been removed from the core, the remaining core or a longitudinal slab of the core that is not less than one half of the cross-sectional area of the core is submitted to the Chief Conservation Officer.

96.15. Before disposing of cuttings samples, fluid samples, cores, evaluation data or other materials taken from a well in compliance with these Regulations, every operator shall notify, in writing, the Chief Conservation Officer and give the Chief Conservation Officer an opportunity to request delivery of the sample, core or data.

Testing and Reporting Requirements for Safety and Environmental Protection Systems

(Would replace sections 123 and 124 of the draft DP Regs)

123. (1) Every operator shall submit to the Board, as part of an application for an operations authorization, a maintenance, inspection and testing program for its facility safety and environmental protection systems.

(2) Every operator shall ensure that the program referred to in subsection (1) results in high reliability of safety and environmental protection systems at any installation.

(3) The program referred to in subsection (1) must consider:

(a) analysis of the testing system as a whole;

(b) if using a risk based methodology, target levels of safety and environmental protection;

(c) the safety and environmental protection system design, specification, and equipment reliability;

(d) operating conditions;

(e) the maintenance program;

(f) the safety and environmental protection system testing frequency;

(g) operating procedures; and

(h) reporting requirements to the Board, in the event of an unsuccessful test of the system or failure of the system, or equipment failure leading to a safety and environmental protection system impairment.

Measurement

(Would replace Part XI, sections 151-170 of the draft DP Regs)

162. Purpose of measurement:

(1) To account for all fluids produced and injected.

(2) To enable reservoir management.

(3) For monitoring compliance with the regulations.

163. Subject to Section 164, every operator shall measure and record the rate of flow and the total volume of:

(a) each fluid that is

(i) produced from each well,

(ii) injected into each well; and

(iii) transferred from, flared, disposed of, or used on the installation;

(b) each fluid that enters or leaves a battery, facility, processing plant, or other installation.

164. (1) Every operator shall submit to the Board an application for approval of a flow system, a flow calculation procedure, and a flow allocation procedure that will permit reasonably accurate determination of the measurements prescribed pursuant to Section 163 and, on a pool and zone basis, the production from and injection into individual wells.

(2) Every operator shall conduct any measurements required pursuant to subsection (1), in accordance with good oilfield practice.

(3) Every operator shall measure and allocate oil, gas and water in accordance with the approved flow system, flow calculation procedure, and flow allocation procedure submitted pursuant to subsection (1) and shall not make any changes to the equipment and procedures outlined therein, without approval of the Board.

(4) Every operator shall allocate group production of oil and gas from wells and injection of a fluid into wells on a pro rata basis to the wells in accordance with the approved flow system, flow calculation procedure, and flow allocation procedure submitted pursuant to subsection (1).

(5) Where a well is completed over multiple pools and zones, every operator shall allocate prorated production or injection volumes for the well on a pro rata basis to the pool and zones in accordance with the approved flow allocation procedure submitted pursuant to subsection (1).

Testing, Maintenance, and Notification

165. (1) Every operator shall calibrate and maintain meters and associated equipment to ensure measurement accuracy is maintained.

(2) Every operator shall ensure that equipment used to calibrate the flow system is calibrated.

(3) Every operator shall repair or replace forthwith any component of the flow system, which is not functioning in accordance with manufacturer's specifications.

(4) Every operator shall notify a conservation officer forthwith, of any malfunction or failure of any flow system component and of the action being taken to remedy the malfunction or failure.

(5) Every operator shall ensure that personnel responsible for the maintenance and operation of the flow system, the flow calculation procedure, and flow allocation procedure are qualified and are properly trained.

(6) The Board may order that any measuring appliance shall be tested or examined in a manner, on the occasions or at the intervals and by the person, specified by the Board.

Transfer Meters

166. (1) Every operator shall notify a conservation officer at least 14 days prior to calibration of any transfer meter prover or master meter used in conjunction with a transfer meter.

(2) Every operator shall submit a copy of the calibration certificate to the Chief Conservation Officer forthwith following completion of the calibration.

Metering Records

167. Every operator shall keep a record of the flow through each group production meter or test production meter used by the operator and retain the record until production from the pool or field is abandoned.

Testing Frequency

168. Every operator of a development well that is producing oil or gas shall test the well at sufficient frequency that will permit reasonably accurate determination of production of oil, gas, and water on a pool and zone basis.