E.20 Suffice it to say, that the HTLS technology advantages, as presented in this Hearing, cry out for recognition by this Board, and ought to be described by this Board to the electrical consumers of this Province as a reasonable alternative, (and "good utility practice"), which this Board has determined to require to HONI to present cost/benefit analyses in order to compare it with the preferred option of HONI. Those HTLS technology advantages include the following:

1. The ACCR conductor weighs only 85% of the weight of equivalent ACSR conductors and therefore has lower weight and tensile constraints on steel lattice towers.

2. The HTLS conductor can be utilized on existing towers in existing corridors by re-conductoring the existing towers with new HTLS conductors, without any requirement for a new set of transmission towers, and thereby eliminating any further need for additional land acquisition for new towers, without the need of OEB or Environmental Assessment approvals, as the installations would only be considered maintenance not requiring leave by this Board or approval under the *Environmental Assessment Act*

3, 500 KV HTLS Conductors may also be capable of being strung on 230KV towers without risk of excess sag, or alternatively would not require taller lattice towers such as the existing 500 LV Line because of the low sag properties of the HTLS conductors, thereby resulting in substantial cost savings to consumers.

4. A conversion, in an orderly fashion over a long time, (10-15 years,) of existing ASCR conductors, to HTLS conductors, would expedite the resolution of congestion load problems and risks, as twice as much power as is presently evacuated and transmitted out of the Bruce could be carried out on the existing

tower networks, with an ability to transmit 100 % more energy on the present tower grid system.

E.21 These Intervenors submit that the HTLS conductors are an alternate technology that is recognized outside of Ontario, also utilized in British Columbia, [*see Supplementary Evidence of the Fallis Group of Intervenors - (Part 3)* , Section 2, p. 9-11, filed June 11th, 2008]. This conductor technology is recognized by the NPCC and other North American coordinating councils,and other electrical system operators in many other jurisdictions have fully recognized HTLS conductors as '*good utility practice*' which many have implemented and which the NPCC encourages to be utilized.

E.22 When HONI received the massive two Volume binders containing over 1500 pages of test reports on the 3M ACCR conductor technology, Mr. Pappas, on Day One (1) of these Hearings, on May 1st, 2008, extracted an admission from HONI Engineer panelist, Mr. Sabiston, (and an Undertaking J1.1 to produce the same), that HONI had done a study on ACCR technology, and that HONI had costed the conductoring on the Bruce to Longwood to Nanticoke 500 KV Lines at a total of $325 Million and that the total cost of all conceptual alternatives was $1.77 Billion.

E.23 Only on May 2nd, 2008 when J1.1 Undertaking was produced was it then determined that the Study consisted of one page, and was a totally unsubstantiated, subjective, cost estimate made by John Sabiston for HONI, prepared only on April 24th, 2008, estimating the cost of all conceptual alternatives, that were not fully known to and/or available to HONI until 6 days before, namely April 18th, 2008 the date of the filing of the Intervenors' evidence. That Undertaking is set out as Appendix "5" hereto..

E.24 These Intervenors submit that this one page sheet contains no useful information for this Board to consider as it is totally void of the quality of information required of HONI to be put before this Board under the rules of the Filing Requirements 5.3.1-2. which are mandated by the

Legislature of Ontario to this Board ***'to protect the interests of consumers as to price, and the adequacy, quality and reliability of electrical services'***

E.25 The Board's Filing Requirements further mandate that **"the applicant is expected to also compare the alternatives versus the preferred option along various risk factors including, but not limited to, financial risk to the applicant, inherent technical risks, estimation accuracy risks, and any other critical risk that may impact the business case supporting the proposed project.** Mr. Sabiston's figures amount to no more than a totally unsubstantiated estimate that should be given no more weight by this Board than hand written notes on the back of a pack of MacDonald Cigarettes.

E.26 These Intervenors repeat their earlier statements of purpose made to this Board, namely they wish to ensure that the fullness of alternatives be placed before your Board so that your Board may satisfy itself that sufficient information is available to allow the Board to make a decision for the benefit of the electrical consumers of Ontario to determine whether or not an Order should be made granting HONI leave to construct its own preferred option.

E.27 These Intervenors submit that if this Board were invited to make further comment on its eventual decision, after it is made, this Board should be able to offer comparison analyses of the various technologies so as to ***protect the interests of consumers as to price, and the adequacy, quality and reliability of electrical services.'*** If this Board does not have that information before it, then that omission from evidence and the consequences thereof must fall squarely on the shoulders of HONI which is otherwise required by Board Rules to provide that information to the Board in the first place. If the comparative information as to identified alternatives is found by this Board not to exist, then HONI has not fulfilled its mandate and this Board must deny HONI leave to construct its preferred option as sought by it under s. 92 of the OEB Act, and so advise the electrical consumers of Ontario in its decision.

E.28 Attached as Appendix '2' to this Argument is a Chart setting out Questions that these Intervenors submit that the electrical consumers of Ontario have the right to understand,

through the review process given to them through this Board, and that this Board should fully answer if the sec. 92 Application of HONI is approved by the Board.

E.29 The electrical consumers of Ontario are entitled to an adequate, reliable and quality electrical service delivered in the most cost efficient manner, and the Legislature has mandated the Board to ensure that entitlement for those consumers.

E.30 These Intervenors therefore submit that the electrical consumers of Ontario are entitled to understand which of the electrical transmission options are financially the most effective, to ensure ***the adequacy, quality and reliability of electrical service*** are maintained for their benefit.

PART IV

RENEWABLE ENERGY GENERATION

F. Renewable Energy:

Need to Inject Good Investor Business Practice to Government Owned Utility Operations

F.1 These Intervenors submit that as generated electrical power from Wind is as fickle as the wind itself, in the event of an SPS emergency, that wind generation must be immediately dispatched as generation rejection before any consideration is given to any other SPS measures to avoid a potential SPS Emergency. HONI stated otherwise through its IESO witness, Mr. Falvo, who said that wind energy would be dropped last as it was the cheapest energy available and ought to be kept to avoid more costly energy purchases. . These Intervenors suggest such logic contradicts the IESO's previous published statement that no new transmission lines are needed if Wind is not a factor.

F.2 Mr. Brill in his Testimony indicated that Florida Power and Light ("FPL") have devised a two-way communication system set up by contract with electrical consumers which allows FPL to immediately load shed 2,500MW of power to consumers which he described as *'load shedding'*, being the equivalent of electrical production from one power plant. He testified, (p. 501-2 of Day 14, June 11 Transcript), as follows:

> **"In Florida, it *('two way communication - smart metering')*, was actually used to prevent having to build an additional power plant. They looked at getting the amount of load up to say: We want to be able to drop up to a power plant's worth of load, which would prevent us having to build that power plant to meet peak demand. So it is a more cost effective way of dealing with the peak by not having to build a power plant to just meet that few hours of peak demand that you see on the system during high load times".**
>
> **(Emphasis added)**

F.3 These Intervenors submit that this cost effective Florida Power & Light concept of designing an equivalent way of dropping or shedding a power plant's worth of load instantly to avoid having to build a power plant to just meet that few hours of peak demand, has direct application to Ontario and must be considered by this Board in the context of the addition of wind energy generation from the Bruce Area.

F.4 As the IESO clearly indicated in its *10 Year Outlook* prepared for the period 2006 to 2015 that with certain technical changes at Nanticoke to make sure that reactive power was continuously available, that there is no need to install new transmission lines to evacuate electrical power from the Bruce Area. Mr. Falvo, of IESO, however indicated in his testimony in these proceedings that the IESO changed its opinion in that regard when it learned that the existing and forecast wind energy to be generated from the Bruce Area was forecast to be 1,700MW nameplate capacity, and that such forecast wind capacity was to be added 6,400MW of nuclear generated electrical power, for a total combined transmission capacity of 8,100 MW.

F.5 That statement by Mr. Falvo put this Application in its true light. The Preferred Option of HONI to construct the 500KV Line has everything to do with wind power generation and really nothing to with nuclear power generation. These Intervenors submit that the electrical consumers of Ontario are being asked to spend $635 Million to evacuate from the Bruce Area of the nameplate potential of 1,700 MW of forecast electrical wind power generation.

F.6 Florida Power and Light is an investor owned utility generating returns for its shareholders. It chose to implement two-way communications to instantaneously load shed up to 2,500 MW, being one power plant's worth of power to avoid building another power plant for a few hours of peak demand. If HONI, the OPA and the IESO were investor owned utilities answering to their shareholders, rather than to their engineers, these Intervenors submit that this Application to build a $635 Million dollar 500KV Transmission Line would not have been brought.

F.8 These Interveners submit that if HONI/IESO can load shed by cutting off the Melancthon Wind Farms from transmitting its renewable energy production for the many months it will take while the 230 KV re-tensioning of the Bruce to Orangeville Line is being carried out HONI/IESO can dispatch all wind power in the Bruce Area for the few hours of peak demand that occur in the Province during each year or during other emergency situations. This would then place the system in exactly the same place as if the 1,700 MW of wind energy from the Bruce Area were NOT a factor. That being the case the statement of the IESO in its 10 year Outlook (2006-2015) would continue to apply namely that no new transmission lines would be needed with adjustments made at Nanticoke.

F.9 As this Board is the public watch-dog to protect the interests of the electrical consumers of Ontario as to price, the savings to be achieved by immediately dispatching 1,700 MW of wind generated electrical power from the Bruce Area during the few hours of peak demand, or other

electrical emergency, at an overall cost savings of $635 Million, (less the cost of any other near-term measures or other electrical facilities installed), will achieve savings for the electrical consumers of Ontario of the equivalent of what excesses would not have been spent if an investor owed company had operated the Ontario transmission system for the benefit of its shareholders.

F.10 These Intervenors submit that the annual interest on $635 Million calculated at 5% per annum would generate $31.75 Million a year or the equivalent of a $33,400 annual reserve for each of about 950 wind turbines that it would take, while producing at nameplate capacity, to generate 1,700MW of electrical power. Considering that each wind turbine generates about 1.8 MW per hour at nameplate capacity, (assuming $110 per hour per MW return for each wind turbine), this represents over 168 hours of generation at nameplate capacity or one full week of generation. At an average generation of 20% of nameplate capacity this would represent 5 weeks of average generation.

F.11 These Intervenors submit that this Board should apply the investor based business model to its evaluation process of the need to build this $635 Million 500 KV Transmission Line. If dispatching 1,700 MW of wind power capacity under a few hours of peak demand, or during other emergencies could avoid the necessity of the expenditure of $635 for a new 500KV Transmission Line, particularly when other reasonable mitigating technologies do exist, and can be implemented at much less cost, then this Board ought to so determine to protect the electrical consumers of Ontario as to price, well knowing that the adequacy, quality and reliability of the electrical services to those same electrical consumers have been otherwise assured by the IESO in its 10 Year Outlook., without the application of other less costly mitigating technologies.

Minister's Directive to secure 2000MW of Additional Renewable Energy by 2015:

F.12 HONI has focused on the "*Directive*" of the Minister of Energy dated August 27th, 2007 to the OPA to assume responsibility for exercising the powers and performing the duties of the Crown in regard to the acquisition of up to 2,000MW of renewable electricity projects that are greater than 10MW in size.(See Tab #4 - HONI Cross-Examination Materials). HONI has represented or mis-represented this '*Directive*' in its cross-examination of Intervenor witnesses as 2000MW of electrical *"wind-generated"* energy.

F.13 Renewable electrical energy generation certainly includes wind, *but* it also includes other forms of renewable electrical energy generation, including new hydro electric generation, solar electric generation, and biomass electrical generation from both waste and wood pellet fuels.

F.14 OPG is presently actively negotiating for the replacement of coal as a fuel at Nanticoke, (a 4,000MW GS), by transforming fuels, gradually switching from coal to wood pellets as a renewable fuel which would satisfy the Ontario Government's intention to eliminate coal burning, and which, when finalized, would also allow for continued electrical energy at Nanticoke, satisfying the need of Bruce for reactive power to be available from Nanticoke to support maximum generation to be available from the Bruce GSS.

F.15 If Nanticoke can be preserved as a major electrical generating facility for the Ontario Electrical Grid this fact is entirely relevant to the considerations before this Board. Even a 50% mix of coal and wood pellet fuel consumption at Nanticoke would have the effect of generating 2000MW of new electrical power from renewable fuel, wood pellets, and would thereby fully satisfy the *Directive* of the Minister of Energy dated August 27th, 2007.

F.16 These Intervenors wish to remind this Board that both Bruce Power LLP and OPG refused to participate in the Interrogatory process, and refused to answer any questions asked of them by these Interveners, notwithstanding that both corporations are integrally part of the electrical generation in Ontario, and their absence and failure to participate in this hearing, (either by the initiatives of HONI ,or on their own decisions), serves only to make information gathering and scoping for these hearings, at the very least, much harder and at the very most, impossible.

F.17 These Intervenors state that the carving out of this Application from what otherwise would be, and ought to be, part of the full considerations of this summer's IPSP hearings for the 20 year Plan, serves only to frustrate the overall requirement for needed fulsome information for these hearings, and also otherwise needed for the fulsome conduct of the 2008 IPSP hearings, and the integrity of those hearings as well.

F.18 These Intervenors submit that the Minister of Energy has not, in his August 27th, 2007 *'Directive'* letter, allocated any particular part of the 2000 MW of additional renewable energy to wind, biomass, solar or hydro electric generation. HONI has however created an impression in these Hearings that renewable energy is all "*wind*", and seemingly that most of it must come from the Bruce Area.

F.19 The eventual transformation and refurbishment of Nanticoke GS to a biomass renewable fuel energy source could occupy all of the renewable electrical energy target potential as set by the Minister of Energy, at 2,000MW by 2015, and thereby would lessen or eliminate the need to necessarily build more transmission capacity out of the Bruce Area to satisfy renewable electrical energy forecasts that may otherwise not require that transmission capability.

F.20 The Melancthon Wind Farms, which will ultimately generate 200MW of power when fully developed, only connect to the 230 KV Transmission Line a distance of 6KM west of its

easterly terminus at Orangeville TS. Those 200 MW could just as easily terminate in the 230 KV Orangeville to Essa Line at or just north of the Orangeville TS, (7 KM of new connecting conductoring only required), and would not then be in the Bruce Area, and would thereby reduce the wind portion of renewable energy from the Bruce by 200MW, and overall generation to 7,900MW from 8,100 MW, and would still deliver generated power to the Ontario Grid.

F.21 HONI has scheduled a planned shut-down of the 230KV line this year to carry out re-tensioning of the 230 KV line as part of its near-term measures. Such shut-down leaves the Melancthon Wind Farms without any connection to the Grid. Not only are the labour and maintenance costs associated with this re-tensioning of the 230KV Bruce to Orangeville line a cost that is associated with the Preferred Option of HONI, but should a cost subsidy be paid by HONI/OPA to the generator owners of the Melancthon Wind Farms for loss of generation abilities due to this shut down of the 230KV line, (and to which the Melancthon Wind Farms power generation connects), this Board should make such a determination upon appropriate investigation. This is a cost that does not appear to ever have been disclosed to this Board by HONI but which, if so subsidized by HONI or the OPA, is a cost about which the electrical consumers of Ontario are entitled to be advised, and information about which this Board ought to now seek information thereon, and to report upon to those electrical consumers.

F.22 These Intervenors submit that if this Board determines that such costs are being incurred by the electrical consumers of Ontario, these costs should be considered a part of the near term measures and added to the overall cost of the Preferred Option of HONI.

PART V

G. RESIDUAL MATTERS

Expected Load Capacities for 230 & 500 KV Transmission Lines

G.1 Mr. Brill, in his testimony, indicated that the load capacities in respect of 230 KV and 500 KV Transmission Lines utilized by Florida Power & Light have the following transmission capacity ranges, expressed in MW. (See p. 552-553 of Day 14, June 11 Transcript):

> **"At Florida Power & Light our 500 kV lines are rated somewhere in the 3,000- to 4,000-amp range, which, is I think if you look at the . . . Megawatt range to compare to, that that gives you around a 2,500- to 3,400-megawatt thermal rating on (y)our *500 lines*, and our *230* lines, while I was down there working at Florida Power & Light, we had a 1,600- amp to about a 3,000-amp rating, which transmits to about 600 to 1,170 megawatts of capacity on the *230* line."**
>
> **(Emphasis added)**

G.2 Mr. Brill analyzed the HONI pre-filed evidence and other later material provided through HONI and determined that HONI's transmission capacity was indeed much less, namely:

> **MR. FALLIS: What did you understand from your review of the HONI evidence, as to the rating capacity, transmission capacity of the 230 and the 500 lines of Hydro One?**
>
> **MR. BRILL: Well, that they were roughly about 2,350 megawatts is the thermal rating on each of the *500* lines out of Bruce. Somewhere in the 300 to 408 range is the thermal limits for the *230* lines out of the Bruce area.**
>
> **(Emphasis added)**

G.3 Comparing FPL transmission capacities based on thermal limits for 500 KV ACSR Conductors lines suggests that HONI transmission Lines are 150MW to 1050MW less than the same type lines operated and utilized by FPL. If the design capacity of the HONI 500KV line is 3,000MW, as HONI promotes the new 500KV ASCR line to be capable of transmitting, then it is reasonable for this Board to inquire and determine whether such losses have been the result of the annealing of the existing 500KV Line from Bruce to Milton from operating in excess of the thermal limits on such Line, thereby reducing its transmission capacity.

G.4 If replacement of the existing double circuit 500KV ASCR conductor is a viable option for the Board to consider for the existing ASCR 500 KV Line from Bruce to Milton, the electrical consumers ought to be advised as to what the additional cost would be for re-conductoring that same line with HTLS conductor cabling when that ASCR line might be removed in any event.

G.5 Comparing FPL transmission capacities based on Thermal limits for 230 KV ACSR conductor lines suggests that these HONI transmission Lines operate at 300MW to 870MW less transmission capacity than the same type 230 KV Lines operated and utilized by FPL. If the design capacity of the HONI 230KV line is much greater, and in the order of the transmission capacity 230 KV Lines of FPL, then it is reasonable for this Board to inquire and determine whether such losses have been the result of the annealing of the existing 230 KV Line from Bruce to Orangeville from operating in excess of the thermal limits on such Line, thereby reducing their transmission capacity. The fact that the 230KV Lines to Orangeville are currently being re-tensioned is proof that they have been allowed to overheat and that the sags resulting from such overheating have caused permanent excessive sagging of the 230 KV ASCR conductors to such an extent that these 230 KV conductors have not returned to their original tensile strength and condition, thereby reducing their transmission capacity.

G.6 If refurbishment of the existing double circuit 230 KV ASCR conductor from Bruce to Orangeville is a viable option, and which HONI has committed to undertake this year, the Board might consider what would be the additional cost for re-conductoring that same 230 KV line with HTLS conductor cabling, and constructing new 230 KV transmission transfer capability only from Orangeville TS to Milton TS to move part of that power beyond Orangeville TS.

Reliability of Existing System with Proposed Reinforcement:

G.7 Mr. Brill examined the load data supplied by HONI and in the SEA Report (April 28, 2008), authored by him, he expresses a very real concern about the combining of 2 x 500KV lines and 1 x 230 KV Line in the same transmission corridor . At p. 10 of his Report he stated:

> **"This appears to contradict the reliability requirements for HONI's transmission system by placing such a large critical power flow through one single corridor. Load data reviewed indicates the existing lines in this corridor, *(1 x 230KV and 1 x 500KV)*, presently carry 60% of the existing generation output of the Bruce Area. The reliability could be at risk from an act of God, accidental, or intentional act, preventing the entire load flow from being carried through this corridor. There would be no other path to carry the loss of power from this corridor out of the Bruce Area"**
>
> **"HONI's interrogatory response to Pappas in Exhibit C, Tab 4, Schedule 12, Page 5 of 5, provides a chart that indicates that with the new Bruce to Milton line and 1000 MW of wind generation installed, the percent of load carried through this corridor approaches 84% of the output of the Bruce area. This increases the risk of an outage affecting this corridor and possibly creating an extensive outage across the Ontario area."**
>
> **" Another concern raised from this chart is that HONI's proposed load flow indicates that the Bruce to Longwood 500KV (B563L and 563L) lines will operate at less than 10% of their rated output. This raises questions on the load flow to the existing line and the justification of the proposed new line (*Chart attached to SEA Report as Attachment 3*)**
>
> **(Emphasis added)**

G.8 This evidence of Mr. Brill was never challenged or disputed and must be accepted by this Board as being a correct interpretation of the information provided by HONI. Placing 84% of generated electricity transmission capacity from the Bruce Area in one Corridor, (when the original planners of the system, Ontario Hydro, created 4 separate corridors, and specifically separated each of the 230KV lines from each other, and separated each of the 500 KV lines from each other), borders upon wanton reckless engineering putting system reliability in potential peril, and which may be the equivalent of again re-building the infamous collapsed Quebec City Bridge using the original plans. For Messrs Falvo, Chow and Sabiston to gloss over that fact, virtually ignore this aspect of reliability, in what appears to be an attempt to otherwise justify straight-line, parallel engineering, defies the most basic element of common reason. The additional extra cost of about 60 feet of land for 180 KM represents just over 818 acres of land. At $5,000 an acre this represents just over $4 million. System reliability is notionally being compromised to save $4M.over the 100 year life of the Line, representing $40,000 a year.

G.9 This Board has said that it will not concern itself with routing matters or alternative route selection leaving the route selection criteria to the EA process. These Intervenors note that one of the four objects that this Board is mandated to consider is 'system reliability'. _These Intervenors submit that '*Reliability*' is not the mandate of the Minister of the Environment under the EA process. The electrical consumers of Ontario are entitled to be provided with information through this Board's decision as to how the proposal of HONI to place 2 x 500KV lines and 1 x 230 KV line in the same overall transmission corridor, (and which will carry load approaching 84% of the output of the Bruce Area), can possibly be considered a 'design reliable system' when the Bruce to Longwood lines will then operate at less than 10% of their rated capacity.

G. 10 These Intervenors suggest that after the construction and transmission start-up of the new Bruce to Milton Reinforcement 500KV line,(if approved), for all practical purposes the Bruce to Longwood Line will be effectively moth-balled with a trickle transmission only, to await a new transmission later use proposal from Bruce Power LLP which may very well propose to use that vastly under-used 500KV line to transmit excess Bruce GSS generation capacity to the United States.

G.11 If correct, these Intervenors suggest the electricity consumer-ratepayers of Ontario,(who will have paid for a new 500KV Line to Milton TS), will also have effectively provided Bruce Power LLP with the opportunity, *available only to it*, to use the 500KV line to Longwood (previously paid for by the electric consumer-ratepayers of Ontario), for transmitting power to the U.S., for the benefit of Bruce Power LLP shareholders, which private company otherwise would have had to build such a inter-connect line to the U.S at their own expense. This may explain why Bruce Power LLP did not participate in these hearings so as to avoid questions being asked of their witnesses about that very real possibility.

Financial Penalties:

G. 12 Mr. Brill notes in the SEA Report; (p. 9), which he authored, that the website of HONI states that:

> **"Failure to place the Bruce to Milton Project in service by December 1, 2011, may prevent available generation capacity in the Bruce Area (about 2,225MW from wind turbine and nuclear power) from being connected to the Ontario Transmission Grid; ie, there would be "stranded generation"**

G.13 Mr. Brill noted in his report (p. 9-10), that HONI states that the Ontario Government will need

to pay a considerable amount as compensation to Bruce Power if the Bruce to Milton Project is not brought into service on time, and due to lack transmission capacity. Quoting again from the HONI website:

> **"Bruce Power will be required to forego their expected revenue resulting from its new generation capacity. Similarly, the contracts for 725MW of committed wind power would also require payment or some form of compensation if the new wind power generation cannot be used due to lack of transmission capacity."**

G.14 Mr. Brill then makes a very astute and poignant observation about these revenue penalties which may cut to the chase, and which may put this Board in a very real dilemma as to whether or not to be able to review the Application through all of its 4 mandated filters of concern, namely to protect consumers as to price, and the adequacy, reliability, and quality of electrical services. He observed:

> **"This statement implies that financial penalties may influence reasons for eliminating other alternatives and technologies in order to move quickly to potentially avoid paying for generation that provides no benefit to the ratepayers"**

G.15 These Intervenors submit that the failure of OPA to make a request of Hydro One Inc. for a new line until March 23rd, 2007 , a delay of over 1.5 years from that date it entered into a contract with Bruce Power LLP, in October, 2005, should not be a factor that this Board ought, in any way, to consider in its deliberations. The mandate of the Board to protect the electrical consumers of Ontario as to *'costs"* relates to the costs associated with the proposed transmission reinforcement project proposed, and to other alternatives including routings and technologies. The 1.5 year delay by the OPA in taking steps to initiate the transmission reinforcement, and the associated costs for such delay, whether through design, mistake, ineptness or negligence, is only a problem for the Ontario Government to resolve, as the sole

shareholder of that Crown corporation, the Ontario Power Authority.

G.16 These Intervenors submit that this Board should ignore the financial problems of the OPA and the financial penalties it may suffer as a consequence of its delays. That is a political problem, not a sec. 92 consideration for this Board. Should a rate increase be subsequently sought by the OPA as a result of penalty payments, this Board will have another opportunity to revisit this issue. This Application is, after all, a *'discretionary development project'* of HONI, and this Board should only look at the Application of the preferred option of the Applicant, HONI, through its usual and normal mandated filters.

G.17 These Intervenors submit that HONI is attempting to clothe itself in the financial problems of the OPA, and to mask their financial problems as being the financial problems of HONI, thereby urging this Board to effectively by-pass its own Rules and Procedures to approve this project by making an Order granting leave to construct the proposed Project.

G.18 These Intervenors submit that the electrical consumers of Ontario deserve much more and urge this Board to intervene on their behalf to financially protect their interests for all of the above reasons.

PART VI

H. COMMENTARY ON BOARD STAFF SUBMISSIONS

Niagara Escarpment Act Development Permit - Mandatory condition

H.1 These Intervenors note that the Board Staff may have overlooked the insertion of an additional clause in its Draft Order, should the Board, determine to otherwise make an Interim Order for

Leave to Construct.. The *Niagara Escarpment Planning and Development Act* makes the following statutory provision therein:

> **Development permits**
>
> **24. (1) Despite any other general or special Act, if an area of development control is established by regulation made under section 22, no person shall undertake any development in the area unless such development is exempt under the regulations or unless the development complies with a development permit issued under this Act. 1999, c. 12, Sched. N, s. 4 (9).**

H.2 The 2005 *Provincial Policy Statement* provides as follows:

> **4.9 Provincial plans shall take precedence over policies in this Provincial Policy Statement to the extent of any conflict. Examples of these are plans created under the *Niagara Escarpment Planning and Development Act* and the *Oak Ridges Moraine Conservation Act, 2001.***

H.3 HONI requires an NEC issued '*Development Permit*' before any development on designated Niagara Escarpment lands may take place. This *Permit* is just as mandatory as EA Approval under the *Environmental Assessment Act* before this reinforcement project can be undertaken by HONI on NEC regulated lands.

H.4 The Draft Order of the Board, if Leave to Construct is granted in this Application, should be so amended to also make specific provision for the condition of issuance of a *Development Permit* under the *Niagara Escarpment Planning and Development Act* before the Approval of this Board is made final by Order of this Board.

PART VII

I. ISSUES LIST

These Applicants, for the reasons set out above, answer the questions raised in the "Issues List" in the following manner: (The answers are set out in the same numeric list as they were established but without setting out the questions which have been well established and are well known to all parties, the Intervenors and the Board). . The

1.0 Project Need and Justification

1.1 The need for the project has not been established -

ANSWER: "NO"

1.2 The project does not qualify as a 'non-discretionary' project under the Board's *'Filing Requirements* for *Transmission and Distribution Applications'*

ANSWER: "NO"

1.3 All appropriate risk factors pertaining to the need and justification have not been taken into consideration

ANSWER: "NO"

1.4 The project is not suitably chosen and sufficiently scalable so as to meet all reasonably foreseeable future needs of significantly increased or significantly reduced generation in the Bruce area.

ANSWER: "NO"

2.0 Project Alternatives

2.1 All reasonable alternatives to the project have not been identified and considered

ANSWER: "NO"

2.2 Appropriate evaluation methodology has not been applied to all of the alternatives considered.

ANSWER: "NO"

2.3 For all considered alternatives the evaluation methodology did not and does not include a cost benefit comparison as well as a comparison of quantitative and qualitative benefits.

ANSWER: "NO"

2.4 (a) Appropriate evaluation criteria and criteria weightings have not been utilized in the evaluation process for alternatives and the the proposed project

ANSWER: "NO"

(b) Appropriate comparisons have not been carried out on all reasonable alternatives with respect to reliability and quality of electrical service including stability and transient levels, voltage performance and Loss of Load Expectation projections under normal and post-contingency conditions

ANSWER: "NO"

(c) The alternatives do meet the applicable standards for reliability and quality of electrical service.

ANSWER: "YES"

2.5 The proposal is absolutely not a better project than the reasonable alternatives.

ANSWER: "NO"

2.6 The projects rate impacts and costs are not reasonable for each of (1) transmission rates, (2) the station modifications, and (3) the Operating, Maintenance, and Administration requirements

ANSWER: "NO"

3.0 Near Term and Interim Measures

3.1 The near term and interim measures as outlined In the Application are not appropriate.

ANSWER: "NO"

3.2 The proposed near term and interim measures can be utilized longer than the suggested two to three year time frame.

ANSWER: "YES"

3.3 The near term and interim measures can be utilized for a period longer than proposed, and they, or a combination thereof, can be considered as an alternative to the double circuit 500KV transmission line for which HONI has applied.

ANSWER: "YES"

4.0 Reliability and Quality of Electricity Service

4.1 For the preferred option the project does not meet the requirements in the System Impact Assessment and Customer Impact Assessment.

ANSWER: "NO"

4.2 The project does not meet applicable standards for reliability and quality of electricity service.

ANSWER: "NO"

4.3 All appropriate project risk factors pertaining to system reliability and quality of electricity service have not been taken into consideration in planning this project.

ANSWER: "NO"

5.0 Land Matters

5.1 The forms of land agreements to be offered to effected landowners are reasonable as far as they go. However there should be an annual perpetual recognition payment paid additionally to Landowners of record on January 1st of each year with a commencement date on the 15th day of February in each year after the in-service date of the Line, if constructed, with cost of living adjustments thereto each year, payments to be paid on all an acreage basis for all transmission lines serving the electrical consumers of Ontario.

ANSWER: "OK" but needs substantial annual recognition payment to landowners

5.2 The question raised is as much a mystery today as it was when it was authored in September of 2007. The EA process has only progressed from August 3rd, 2007 to the point of approving the Terms of Reference, (ToR), in early April 2008, and the Minister of the Environment will hand down a decision 30 weeks later, (without conducting any hearing process whatsoever), leaving it to landowners to request a review before the *Environmental Review Tribunal*, a process that does not have a current timetable for conclusion.

This Hearing process is so far down the road towards a final decision conclusion before the EA process has even got off the ground. The two processes could NOT be more out-of-sync with each other - The processes are not in-step and could not be more out-of-step. *[Attached as Appendix No. # 4 hereto is copy, (poor quality fax) of the California Public Utilities Commission (CPUC) - Time Lines established for each of the CEQA and CPCN processes that may assist this Board in understanding how the synchronization of the two processes happens in California*]

What complicates the process even more is the fact that HONI made no disclosure to this Board of the necessity to obtain a "Development Permit" from the NEC under the *Niagara Escarpment and Planning and Development Act*, which Permit, if not granted will frustrate this entire proceeding and Application.

HONI has made a most cavalier Application, assuming a *"right of passage"*, without regard for orderly and proper process. The final EA decision is realistically probably a year away and with every probability of a long and protracted *Environmental Review Tribunal Hearing.*

(These Intervenors do indeed hope that the failure of process under this *Act* to allow the NEC senior planner to attend to explain to this Board the issues that this Application has upon NEC jurisdiction over the Lands which it is charged with protecting, will not have served to effect a schism between this hearing process and the planning processes under the NEPDA)

ANSWER:
"ABSOLUTELY UNSURE !"

6.0 Aboriginal Peoples Consultations

These Intervenors do not have sufficient information to offer meaningful comment.

7.0 Conditions of Approval

The Board will make an Order as it is mandated so to do.

A. This Board may order that Leave to Construct is NOT granted. No conditions need to be added to such a decision. However the decision should be constructive in nature so that HONI can take guidance from this Board on what alternative, if any, it may have considered approving, provided certain additional information had been provided to the Board which met minimum evidentiary levels to allow the Board to make a cogent comparative decision.

HONI should be granted leave to re-apply to this Board, if needed.

B. If this Board grants HONI leave to construct, such Order must be stated clearly to be conditional, and with referral back to this Board for finalization, but only after receiving:

1. Final approval under the *Environmental Assessment Act*, and all appeals therefrom have first exhausted, and

2. A Development Permit under the *Niagara Escarpment Planning and Development Act*, and all appeals therefrom have first exhausted.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 4th DAY OF JULY, 2008

PETER T. FALLIS

Counsel for the "Fallis Group of Intervenors"

PART VIII

APPENDICES

OPERATING EXPERIENCE HISTORY OF REACTOR UNITS AT DOUGLAS POINT AND BRUCE "1 - 8" FROM 1977 TO 2006

(FROM INFORMATION RECORDS OF THE INTERNATIONAL ATOMIC ENERGY AGENCY - VIENNA, AUSTRIA)

REACTOR	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
D. POINT	206	206	206	130	206	206	206	206										
BRUCE 1	740	740	740	740	740	740	740	740	848	848	848	848	848	848	848	848	848	848
BRUCE 2	740	740	740	740	740	740	740	740	781	848	848	848	848	848	848	848	848	848
BRUCE 3		740	740	740	740	740	740	740	775	796	848	848	848	848	848	848	848	848
BRUCE 4			740	740	740	740	740	740	788	848	848	848	848	848	848	848	848	848
BRUCE 5								854	805	860	835	860	860	860	860	860	860	860
BRUCE 6								822	805	835	837	837	837	852	860	860	860	860
BRUCE 7										838	837	846	860	860	860	860	860	860
BRUCE 8											844	837	842	860	860	860	860	860
* TOTAL MWe GENERATION CAPACITY	1,686	2,426	3,166	3,090	3,166	3,166	3,166	4,842	4,802	5,873	6,745	6,772	6,791	6,824	6, 832	6,832	6,832	6,832

* Based on Historic Records of the International Atomic Energy Commission (IAEA)created from IAEA Website on April 7th, 2008. **(Expressed in MWe)**

OPERATING EXPERIENCE HISTORY OF REACTOR UNITS AT DOUGLAS POINT AND BRUCE "1 - 8" FROM 1977 TO 2006

(FROM INFORMATION RECORDS OF THE INTERNATIONAL ATOMIC ENERGY AGENCY - VIENNA, AUSTRIA)

REACTOR	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
D. POINT												
BRUCE 1	848	848	848									
BRUCE 2	848											
BRUCE 3	848	848	848	848						750	750	750
BRUCE 4	848	848	848	848					769	769	750	750
BRUCE 5	860	860	860	785	785	785	790	790	790	790	790	806
BRUCE 6	860	860	860	860	785	785	790	790	790	790	841	822
BRUCE 7	860	860	860	785	785	785	790	790	790	790	790	806
BRUCE 8	860	860	860	785	785	785	790	790	790	790	790	790
* TOTAL MWe GENERATION CAPACITY	6,832	5,984	5,984	4,911	3,140	3,140	3,160	3,160	3,929	4,679	4,711	4,724

* Based on Historic Records of the International Atomic Energy Commission (IAEA)created from IAEA Website on April 7th, 2008, . **(Expressed in MWe)**

\\Peter1\storage (d)\A.COMMERCIAL\08 COM\Hydro Transmission Lines 2008\IAEA Historic Generation Chart 1997 to 2006 for the Bruce.wpd

OPERATING EXPERIENCE HISTORY OF REACTOR UNITS AT DOUGLAS POINT AND BRUCE "1 - 8" FROM 1977 TO 2006

(FROM INFORMATION RECORDS OF THE INTERNATIONAL ATOMIC ENERGY AGENCY - VIENNA, AUSTRIA)

COMMENTS:

CHART FILED BY HONI AS Exhibit 'C' - Tab 4 - Schedule 12, p. 4 of 5, discloses that:

1. Until 1979, the 500 KV Line was not yet in service.
2. Until 1979 the only Transmission lines leaving BRUCE GSS were:
   - i. 230 KV - Bruce to Hanover/Orangeville - In service Nov. 26, 1963
   - ii. 230 KV - Bruce to Detweiler - In service Oct. 11, 1975
   - iii. 230 KV - Bruce to Owen Sound - In service Oct. 31, 1977
3. The 500 KV line from BRUCE to Milton first operated as a 230KV line to Belwood Junction to add capacity before construction of 500KV line to Milton was completed.
4. Before 1979, the generation capacity of : Douglas Point Unit and Bruce Units " 1 - 2" was 1,646 MWe in 1977 and
   Douglas Point Unit and Bruce Units " 1 - 3" was 2,426 MWe in 1978
5. Before 1979 Three (3) 230 KV Lines transmitted all of the net generation capacity available from the gross capacity of 2,426 MWe before any 500 KV Lines were built
6. In 1979 the 500 KV Bruce to Milton Line was operated as a 230 KV until April 1, 1983, and Douglas Point and Bruce '1 - 4' generated 3,166 MWe except for 1980 when they generated 3,090 MWe
7. From 1987 to 1995 the generation capacity of all 8 Units at the Bruce was as low as 6,745 MWe to a high of 6,832 MWe.

COST RELATED QUESTIONS FOR CONDUCTOR CHOICE	ASCR $(M)	ACSS ($M)	ACCR ($M)
1. What is the estimated cost the supply of sufficient 500 KV Conductor cabling for 180 KM running from The Bruce to Milton on the preferred route choice of HONI (f.o.b job site) - supported by cost estimate from manufacturer/supplier?			
2.What is the estimated cost for land acquisition for the proposed 500KV Transmission within the preferred route corridor choice of HONI?			
ASCR: **3.** What is the estimated cost of the steel for the Towers and separate cost for their erection, supported by cost estimates for the proposed 500 KV Transmission line? **3A.** What is the cost estimate of re-adjusting the existing 230 KV line from Bruce to Hanover to Orangeville **3B.** What cost will HONI/OPA/ and the electrical consumers of Ontario suffer during the re-adjustment of Bruce to Orangeville 230KV Line which will not bee in operation during 230 KV adjustment period in respect to locked in power potential from Melancthon Wind farm, (approx 100MW Nameplate capacity), which only connects to the Ontario Grid through that 230 KV Line approx. 6 km west of Orangeville			
ACSS: **4.** Need to determine comparative weight of ACSS conductor cable to compare with ACCR to determine if it can be installed on both 230 KV and 500 KV a can be utilized. If ACSS conductors can be installed on existing 230 KV Line to transmit 500KV of electricity, no additional land will be required.			

ACCR: **5.** What is the cost of reconductoring either the 500 KV Line from Bruce to Milton with ACCR conductor cabling or the 230 KV line from Bruce to Orangeville with new Towers from Orangeville to Milton only, including removing existing conductors and replacing with HTSL conductors			

FREQUENTLY ASKED QUESTIONS ABOUT THE CALIFORNIA PUBLIC UTILITIES COMMISSION'S CALIFORNIA ENVIRONMENTAL QUALITY ACT PROCESS

1. What is CEQA?

CEQA stands for the California Environmental Quality Act of 1970. CEQA is a California law that requires state and local agencies to consider potential environmental effects prior to approving new activities and to avoid or mitigate significant impacts whenever feasible. The basic purpose of the law is to: (1) inform decision makers and the public about the possible environmental effects of proposed projects; (2) identify ways that environmental damage can be avoided or reduced; (3) require changes in projects through the use of less damaging alternatives or mitigation measures when feasible; and (4) where the agency is approving a project despite remaining significant environmental effects, require the agency to explain why.

2. When does CEQA apply?

State and local agencies must comply with the requirements of CEQA whenever they consider approving any proposed action defined by CEQA as a "project". A project is an activity that requires the discretionary approval of a government agency, such as the grant of a construction permit, which may cause either a direct physical change in the environment or a reasonably foreseeable indirect change in the environment.

3. How does CEQA affect the CPUC's work?

The basic mission of the CPUC is to regulate investor-owned telecommunications, electric, natural gas, and water utilities operating in the State of California. This group of utilities includes big investor-owned utilities (IOUs) that you may be familiar with, such as Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company and AT&T. It also includes many smaller utilities, such as PacifiCorp and Sierra Pacific. The CPUC does not regulate municipally-owned utilities such as the Sacramento Municipal Utility District or the Los Angeles Department of Water and Power.

The CPUC oversees almost all large utility construction projects. It also considers approval of other types of utility activity that might have a significant impact on the environment. Most of the CPUC's CEQA obligations arise in the context of the CPUC's review of utility construction permit requests, where the CPUC is usually the "lead agency" for CEQA review purposes.[1] When a utility wants to construct something, such as a transmission line, it must generally apply for a permit from the CPUC, called a "Certificate of Public

[1] Note that where an investor-owned utility coordinates with a local government or municipally-owned utility, the CPUC may not be the lead agency for CEQA purposes. Instead, the CPUC may be a responsible agency that may coordinate in the development of the environmental documents.

Convenience and Necessity" or "CPCN."[2] Before the CPUC can rule on a utility's application for a CPCN, the CPUC must comply with CEQA by analyzing the environmental impacts of the proposed project.

4. How does the CEQA process work within the CPUC's CPCN process?

Whenever the CPUC considers whether or not to grant a CPCN application or any other project, the CPUC must (1) inform the public about the possible environmental effects of the proposed project; (2) identify ways that environmental damage that may be caused by the proposed project can be avoided or reduced; (3) require changes in the proposed project through the use of alternatives or mitigation measures when feasible; and (4) explain why the CPUC will approve a project despite remaining significant environmental effects, explain why.

When a utility files a CPCN application, the application must include a "Proponent's Environmental Assessment" (PEA) that describes the utility's view of the environmental impacts of the proposed project. Energy Division staff within the CPUC work with consultants to determine whether to issue a negative declaration, a mitigated negative declaration (MND) or an environmental impact report (EIR). Consistent with the requirements of CEQA, there are many opportunities for public participation and comment during the development of the CEQA strategy, alternatives to the project that may be studied, and the development and issuance of the draft and final environmental documents. A simple step-by-step explanation of this CEQA process, described within the context of a CPCN proceeding, is available at:

http://www.cpuc.ca.gov/static/energy/environment/cpcnprocess.doc.

A timeline that shows the relationship between the CEQA and CPCN processes is available at:

http://www.cpuc.ca.gov/static/energy/environment/document.pdf

As the step-by-step explanation and the timeline demonstrate, the CPUC's CEQA process occurs in parallel with the CPCN process and a CPCN cannot be issued until the CEQA process is completed.[3] After the CEQA process and a final environmental analysis are completed, the Administrative Law Judge (ALJ) overseeing the CPCN writes a draft decision based on the CEQA documentation and testimony from parties to the proceeding.

[2] Depending upon the scale of the project, the utility may apply instead for a "Permit to Construct" or "PTC." For simplicity, this document refers to both CPCNs and PTCs together as a CPCN.
[3] Please note that where the CPUC is not the lead agency for CEQA purposes, the CEQA process may be completed by another agency prior to the utility filing its application for a CPCN.

It is important to recognize that the final CEQA analysis is an informational environmental document only. It does not make a recommendation regarding the approval or denial of the CPCN application, and it does not establish the route or location for the proposed project

(where relevant). The purpose of the final environmental document is to inform both the public and the decision makers of the environmental impacts of the proposed project and alternatives, and to identify, from a purely environmental perspective, a preferred route or location (where relevant). In making a final determination on the application, the Commission will consider many other non-environmental factors such as community values, historical values, the existence of recreational and park areas, whether the utility has demonstrated that the project is needed and whether the estimated cost of the proposed project is reasonable. The ALJ and the Commission consider the final environmental documents, along with alll these other issues, during the preparation of the decision on the CPCN application. Environmental concerns do not bind the Commission, and the Commission has the authority to issue a Statement of Overriding Consideration allowing other factors to take precedence over environmental concerns.

The Commissioners vote on the ALJ's draft or a commissioner's alternative decision at a Commission meeting. If the Commission approves a decision, the utility is either issued or denied a CPCN. When it receives a CPCN, the utility can proceed with the project, pending necessary approvals from other agencies.

5. What affect does CEQA have on proposed utility projects?

CEQA requires the CPUC to identify the significant environmental impacts of a proposed project, and if the project is going to be approved, to develop measures, where feasible, to avoid or reduce those impacts. At a minimum, CEQA requires an initial review of the project and its environmental effects to be identified and addressed. Depending on this initial analysis, a further and more substantial review may be required through either a mitigated negative declaration (MND) or an environmental impact report (EIR). Under CEQA, a proposed project may not be approved as submitted if feasible alternatives or mitigation measures are able to reduce the significant environmental effects of the proposed project. Thus, the environmental review of the proposed project must be completed prior to the agency's decision, in order to influence the proposed project's plans or design.

6. Which types of utility projects need to go through the CEQA process?

The CPUC regulates investor-owned telecommunications, electric, natural gas, and water utilities operating or wishing to operate in California. The CPUC must comply with the requirements of CEQA when it approves any requested utility action that may cause either a direct physical change in the environment or a reasonably foreseeable indirect change in the environment. See the answer to FAQ No. 0, above, for further discussion on this issue.

7. What role can the public play in determining how a utility's proposed project is reviewed during the CEQA process, and whether or not a CPCN is granted?

The CPUC's CEQA and CPCN processes are two distinct processes that run in parallel to each other during the CPUC's consideration of the CPCN application.

The CEQA process was established based on the belief that citizens hold a privileged position in the public agency planning process and can make important contributions to environmental protection. Consistent with the requirements of CEQA, there are many opportunities for public participation and comment during the CEQA process, including public participation in the development of the CPUC's CEQA strategy and alternatives to the project that may be studied (this is the CEQA "scoping" process), and the development and issuance of the final environmental documents (public comments, both written and oral, are taken during the development of the draft and final environmental documents). A simple step-by-step explanation of this CEQA process, described within the context of a CPCN proceeding, is available at:

http://www.cpuc.ca.gov/static/energy/environment/cpcnprocess.doc.

As set forth in the step-by-step guide described above, the CPCN process is separate from the CEQA process. Participation in the CPUC's CPCN process requires formal intervention in the proceeding, and may involve the filing of expert witness testimony. Intervenor compensation is available to parties who wish to participate in the CPCN portion of the CPUC's decision-making process, provided they make a significant contribution to the proceeding that does not duplicate the work of other parties. Additional information about this process and the availability of intervenor compensation is available through the CPUC's Public Advisor's Office and at the following link:

http://www.cpuc.ca.gov/static/aboutcpuc/divisions/csid/public+advisor/publicpartici pation.htm

See also the answer to FAQ No. 8, below regarding the assistance provided by the Public Advisor's Office.

8. Can I get assistance with determining the steps I need to take to have my voice heard through the CPUC's CEQA or CPCN processes?

The CPUC Public Advisor's Office provides procedural information and advice to groups and individuals who want to comment or advocate positions in the CPUC's formal proceedings. The Public Advisor's staff helps answer questions, locate information, or refer callers to the appropriate staff person. The Public Advisor's staff also attends community functions and assists the public in participating in CPUC proceedings, and town hall meetings, etc. You may contact the Public Advisor's Office at: CPUC Public Advisor, 505 Van Ness Avenue, Room 2103, San Francisco, CA 94102; or call (866) 849-8390 or (415) 703-2074; or e-mail public.advisor@cpuc.ca.gov. Additional information regarding the CPUC's Public Advisor is available at:

http://www.cpuc.ca.gov/static/aboutcpuc/divisions/csid/public+advisor/

FREQUENTLY ASKED QUESTIONS ABOUT THE CALIFORNIA PUBLIC UTILITIES COMMISSION'S CALIFORNIA ENVIRONMENTAL QUALITY ACT PROCESS

9. Who is responsible for CEQA compliance and enforcement?

It is each government agency's obligation to ensure compliance with CEQA. Where the agency fails to comply with CEQA, the public may enforce compliance with CEQA through the courts. Attorney fees and costs may be available to those who are successful in enforcing CEQA through the courts.

10. What is a Negative Declaration? How does that compare with a Mitigated Negative Declaration (MND)? How are those different from an Environmental Impact Report (EIR)?

The CEQA analysis of a project will result in either an Environmental Impact Report (EIR), a Mitigated Negative Declaration (MND), or a Negative Declaration (ND).

An Environmental Impact Report (EIR) is prepared when the public agency finds substantial evidence that supports a fair argument that the project may have a significant effect on the environment.

A Mitigated Negative Declaration (MND) is prepared for a project when the initial study identifies potentially significant effects on the environment, but: (1) revisions in the project plans or proposals would avoid the effects to a point where clearly no significant effect on the environment would occur; and (2) there is no substantial evidence that the project, as revised, may have a significant effect on the environment.

A Negative Declaration is prepared when an agency finds that there is no substantial evidence that a project will have a significant effect on the environment.

11. What is a "lead agency"? or Who prepares the environmental analysis?

Under CEQA, the lead agency is the California government agency that has the principal responsibility for carrying out or approving a project; the lead agency is the agency responsible for preparing the environmental study. The lead agency decides whether a Negative Declaration, MND, or EIR will be prepared, and determines the scope and content of that document. Where the CPUC is the lead agency on a project, the CPUC hires environmental consultants to assist in the preparation of the environmental studies.

12. What is a significant effect on the environment?

The CEQA Guidelines (14 California Code of Regulations) § 15382 define a "significant effect on the environment" as:

> a substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project, including land, air, water, minerals, flora, fauna, ambient noise, and objects of historic or aesthetic significance.

> An economic or social change by itself shall not be considered a significant effect on the environment. A social or economic change related to a physical change may be considered in determining whether the physical change is significant.

Please see the answer to FAQ No. 13 for additional information on the issue of significant impacts.

13. If there is a significant environmental impact does that mean that the project can't be built?

No. When an EIR shows that a project would cause substantial adverse changes in the environment, the agency must respond to the information by one or more of the following methods: (1) changing the proposed project; (2) imposing conditions on the approval of the project; (3) adopting plans or ordinances to control a broader class of projects to avoid the adverse changes; (4) choosing an alternative way of meeting the same need; (5) disapproving the project; or (6) finding that changing or altering the project is not feasible and that the need for the project overrides the unavoidable significant environmental damage it will cause.

14. What role do the Department of Fish and Game and other state agencies (with relevant knowledge and jurisdiction) have in the CEQA process? or What is a Responsible or Trustee Agency?

In addition to the Lead Agency that prepares the environmental document, there are Responsible and Trustee Agencies. A Responsible Agency includes any public agency, other than the Lead Agency, which has discretionary approval power over the project. *See* CEQA Guidelines §15381. A Trustee Agency is a state agency having jurisdiction by law over natural resources affected by a project which are held in trust for the people of the State of California. *See* CEQA Guidelines § 15386. Trustee agencies include: the California Department of Fish and Game, the State Lands Commission; the State Department of Parks and Recreation; and the University of California. The Lead Agency must include Responsible and Trustee Agencies in the development of the environmental document. This can include pre-application consultation, and must include sending the formal Notice of Project and draft EIRs to these agencies so that they can provide comments on the scope and content of the environmental document.

15. Does the CPUC ever share the lead with another agency to do a CEQA analysis?

Under CEQA, any agency other than the Lead Agency that has responsibility for carrying out or approving a project is known as a "Responsible Agency". A responsible agency should actively participate in the Lead Agency's CEQA process, review the Lead Agency's CEQA document, and use the Lead Agency's CEQA document when making a decision on the project.

16. Are electric and magnetic fields (EMFs) considered in the CPUC's CEQA process?

FREQUENTLY ASKED QUESTIONS ABOUT THE CALIFORNIA PUBLIC UTILITIES COMMISSION'S CALIFORNIA ENVIRONMENTAL QUALITY ACT PROCESS

The Commission first established EMF policies in D.93-11-013. In its recent review of EMF issues, the Commission stated in D.06-01-042 that, "at this time we are unable to determine whether there is a significant scientifically verifiable relationship between EMF exposure and negative health consequences." It affirmed in D.06-01-042 that the Commission's EMF policy is one of prudent avoidance, with application of low-cost/no-cost mitigation measures to reduce EMF exposure for new and upgraded utility transmission and substation projects. The Commission has adopted a benchmark of 4% of total project cost for low-cost EMF mitigation measures, with flexibility to allow expenditures above the 4% benchmark if justified by a project's unique circumstances. In D.06-01-042, the Commission stated that, as a guideline, low-cost EMF mitigation measures should reduce EMF levels by at least 15% at the utility right of way.

As a general rule, an EIR will provide information regarding EMF associated with a proposed project. However, it does not consider magnetic fields[4] in the context of CEQA and determination of environmental impact because there is no agreement among scientists that EMF creates a potential health risk, and there are no defined or adopted CEQA standards for defining health risk from EMF.

Under the Commission's rules, the utility must include, in its application, a description of the measures taken or proposed by the utility to reduce the potential exposure to EMFs generated by the proposed facilities (General Order 131-D, Section X.).

In D.06-01-042 the Commission directed the utilities to hold a workshop to develop standard approaches for EMF Design Guidelines that meet the Commission's low-cost/no-cost policies. This workshop was held in the spring of 2006 and the EMF Design Guidelines are a result of that workshop. The guidelines describe the routine magnetic field reduction measures that all regulated California electric utilities will consider for new and upgraded transmission line and transmission substation projects. The EMF Design Guidelines are available at:

http://www.cpuc.ca.gov/static/energy/environment/electromagnetic+fields/index.htm

Decision No. 06-01-042 is available at:

http://www.cpuc.ca.gov/static/documents/index.htm

[4] Because electric fields are shielded effectively by materials such as trees and walls, the emphasis in our consideration of EMF is on exposure to magnetic fields.

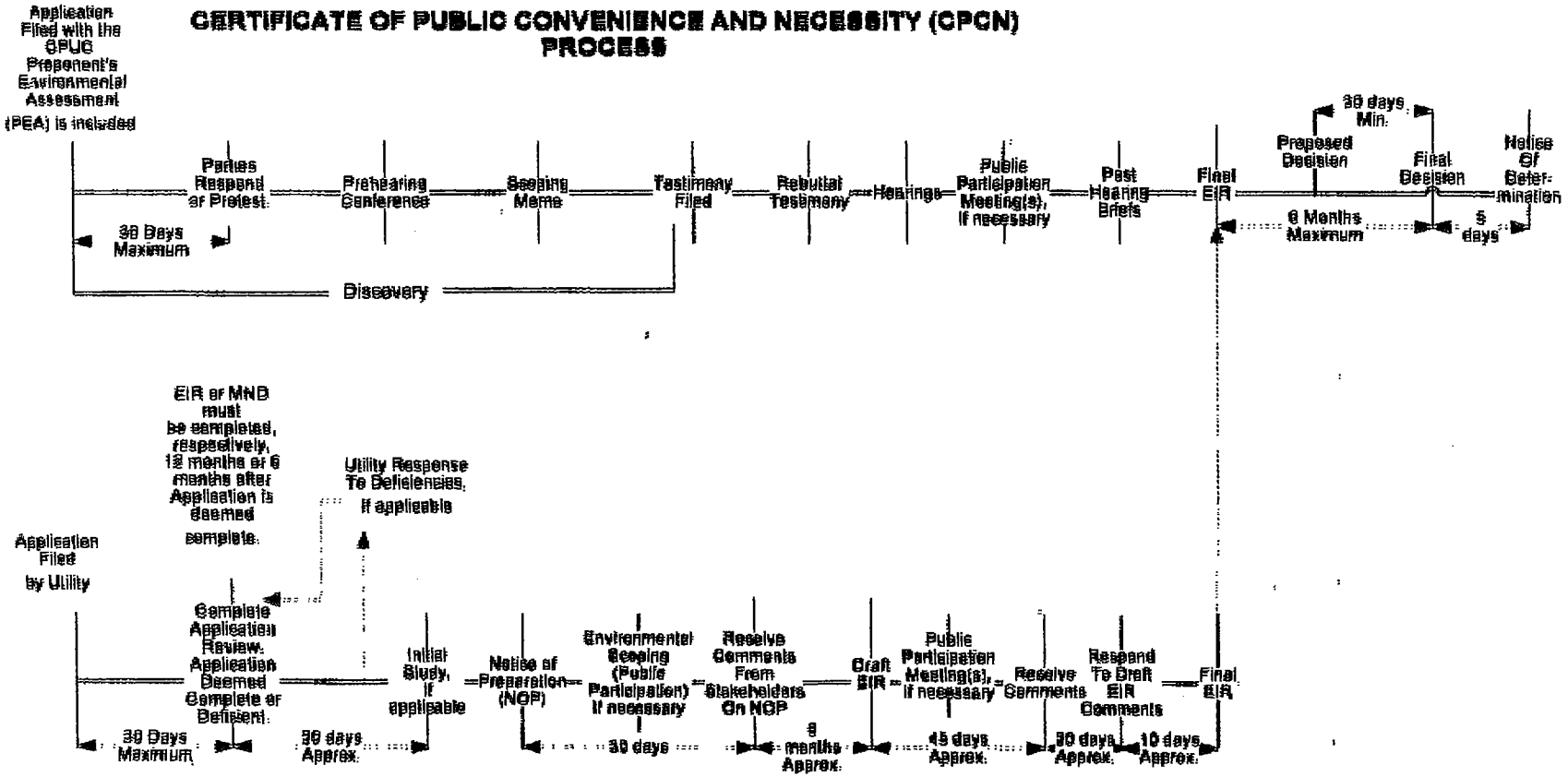
FREQUENTLY ASKED QUESTIONS ABOUT THE CALIFORNIA PUBLIC UTILITIES COMMISSION'S CALIFORNIA ENVIRONMENTAL QUALITY ACT PROCESS

17. How can I learn more about CEQA?

Additional information about CEQA, including the text of the law and the text of the CEQA Guidelines is available at:

http://ceres.ca.gov/ceqa/

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY (CPCN) PROCESS



CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA) PROCESS

* This is a typical CPCN and Environmental Impact Report (EIR) CEQA timeline, however, the schedule may vary based on the complexity of the project.

October 2006

WORKING PAPER RE:
CONCEPTUAL ALTERNATIVES TO A NEW 500 KV BRUCE TRANSMISSION LINE
Reinforcing the Path Through Longwood using HTLS, SC & SVC's

Description of Conceptual Alternative	Cost Estimate ($ M)
Bruce x Longwood (B562L & B563L): Provide 2 x 70% 500 kV series capacitor installations rated at 4000 A, each one consisting of a 30% fixed series cap bank and a 40% Thyristor Controlled Series Capacitor (TCSC) bank. Install at a new station site near Grand Bend. Assume protection modifications at all terminal stations, protection and control and monitoring.	265
Nanticoke x Longwood (N582L): Provide 1 x 70% 500 kV series capacitor installation rated at 5,000 A continuous consisting of a 30% fixed series cap bank and a 40% TCSC installation. Install at a new station site near Tillsonburg. Assume protection modifications at all terminal stations, protection and control and monitoring.	180
Bruce x Longwood (B562L & B563L): Reconductor with a conductor that can achieve an ampacity at 35 degrees C, 4 km/h wind of at least 4,000 A continuous without requiring structure changes. This could be either quad 732 compact conductor if that conductor can achieve that rating, or a high temperature low sag conductor such as ACCR. Needs to be confirmed	220
Nanticoke x Longwood (N582L): Reconductor with a conductor that can achieve an ampacity at 35 degrees C, 4 km/h wind of at least 5,000 A continuous without requiring structure changes. This could be either quad 732 compact conductor if that conductor can achieve that rating, or a high temperature low sag conductor such as ACCR	105
Install the Following SVC's. Each SVC to consist of banks of Thryistor Switched Capacitors (TSC) with coupling transformers similar to the 350 MVAr TSC's recently estimated for business planning purposes at Nanticoke & Detwieler TS	
1. Longwood TS, 1 x 350 MVar and 1 x 150 MVAr connected at 500 kV	125
2. Nanticoke TS, 4 x 350 MVAr (2 connected at 230 kV & 2 at 500 kV) and 1 x 150 MVAr connected at 500 kV	310
3. Milton SS, 1 x 350 MVar and 1 x 150 MVAr connected at 500 kV. Assume two new 500 kV GIS breakers	150
4. Detweiler TS, 1x 350 MVAr connected at 230 kV	70
Reconductor the following 230 kV circuits with high sag low temperature conductor that can achieve an ampacity at 35 degrees C, 4 km/h wind of at least 2,000 A continuous with requiring structure changes. On circuits with taps, reconductor the main circuits only:	
1. W42L & W43L (Longwood x Buchanan)	25
2. W44LC & W45LC (Longwood x Buchanan x Chatham)	50
3. D4W & D5W (Detweiler x Buchanan)	35
4. M31W, M32W & M33W (Middleport x Buchanan)	65
5. T36B, T37B, T38B, & T39B) Trafalgar x Burlington	30
6. R14T, R17T, R19T & R21T (Richview x Trafalgar)	25
Install 30% fixed 230 kV series capacitor banks rated at 2,000 A continuous at new station sites located at the approximate mid-points of the following 230 kV circuits.	
1. W42L	10
2. W43L	10
3. W44LC (Longwood x Buchanan section)	10
4. W45LC (Longwood x Buchanan section)	10
5. D4W	15
6. D5W	15
7. M31W	15
8. M32W	15
9. M33W	15
GRAND TOTAL OF ALL ALTERNATIVES	1770
Note: Cost estimates are based on past similar projects and/or engineering judgement.	

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