Hydro Québec

Le 16 décembre 2008

Yves Fréchette
Avocat

Hydro-Québec – Affaires juridiques
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Par courriel et messager

Me Véronique Dubois
RÉGIE DE L'ÉNERGIE
800 Place Victoria
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Montréal (Québec)
H4Z 1A2

OBJET : Dépôt – Suivi administratif des critères de fiabilité selon la décision D-2008-133
Plan d'approvisionnement 2008-2017 du Distributeur
Notre dossier : R000299 YF

Chère consœur,

Dans le cadre du suivi administratif concernant les critères de fiabilité établis par la décision D-2008-133, vous trouverez ci-jointe la documentation suivante, à savoir :

Annexe A : Respect du critère de fiabilité en énergie d'un écart type pour le Distributeur.

Annexe B : Respect du critère de fiabilité en énergie pour les approvisionnements provenant d'Hydro-Québec Production.

Annexe C : Respect du critère de fiabilité en puissance – Bilan d'Hydro-Québec Production (**confidentiel**).

Annexe D : Respect du critère de fiabilité en puissance – Bilan du Distributeur.

Annexe E : Respect du critère de fiabilité en puissance : Conciliation des données (**confidentiel**).

Annexe F : Lettre d'attestation de la fiabilité énergétique du parc de production d'Hydro-Québec Production.

Annexe G : Extraits du 2008/2009 Winter Reliability Assessment du NERC

Annexe H : Revue Triennale 2008 du Québec (version préliminaire) soumise au NPCC (**confidentiel**).

À titre de rappel, la décision D-2008-133 (pp. 20 et 21) a maintenu la confidentialité des annexes C et E ci-jointes. Le Distributeur demande à la Régie, dans le cadre de son suivi administratif, de maintenir la confidentialité de l'annexe C, jusqu'au 31 janvier 2009. Quant à l'annexe E, dans la mesure où les informations qu'elle contient se retrouvent à l'annexe H, nous demandons de maintenir la confidentialité de cette annexe jusqu'au 31 mars 2009 pour les motifs ci-après décrits.

En ce qui concerne l'annexe H, une version préliminaire de la Revue Triennale 2008 du Québec a été soumise au NPCC le 10 décembre 2009. Des commentaires ont été recueillis et seront intégrés dans la version définitive de cette Revue qui devrait être approuvée par le NPCC en mars 2009. Dans l'intervalle, le Distributeur demande à la Régie de maintenir la confidentialité de l'annexe H et ce, jusqu'au 31 mars 2009.

Nous vous prions d'agréer, chère consœur, l'expression de nos meilleurs sentiments.

Yves Fréchette

/nm

p.j. Annexe A
Annexe B
Annexe C (confidentiel)
Annexe D
Annexe E (confidentiel)
Annexe F
Annexe G
Annexe H (confidentiel)

ANNEXE A

RESPECT DU CRITÈRE DE FIABILITÉ EN ÉNERGIE DU DISTRIBUTEUR POUR L'ANNÉE 2009 (1 ÉCART-TYPE AU-DELÀ DU SCÉNARIO MOYEN) EN TWH

ANNEXE A
Respect du critère de fiabilité
en énergie du Distributeur pour l'année 2009
(1 écart-type au-delà du scénario moyen)
en TWh

	Année 2009
Besoins visés par le Plan	183,7
+ Impact de l'aléa global sur les besoins (1 écart-type)	3,7
Besoins d'un scénario de demande plus élevée	187,4
- Volume d'électricité patrimoniale (incluant les pertes)	178,9
= Approvisionnements additionnels requis au-delà du volume d'électricité patrimoniale	8,5
Moins : Approvisionnements existants	6,7
- TransCanada Energy	0
- Hydro-Québec - Base	3,1
- Hydro-Québec - Cyclable	2,2
- Contrats de biomasse	0,3
- Contrats signés - Éolien I (990 MW)	1,1
= Dépendance envers les marchés de court terme	1,8

ANNEXE B

RESPECT DU CRITÈRE DE FIABILITÉ EN ÉNERGIE POUR LES APPROVISIONNEMENTS PROVENANT D'HYDRO-QUÉBEC PRODUCTION

Hydro-Québec Production – État des réserves et de la fiabilité énergétique

Critère de gestion – 2 ans à 2% de probabilité (-64 TWh) – Cycle des années 2009-10

A- Stock énergétique au 1er janvier 2009 (prévu) : 114,3 TWh

B- Stock énergétique prévu au 1er mai 2011 à hydraulicité normale en 2009/2010 : 70,8 TWh

C- Application du critère de gestion :

- cycle de faible hydraulicité à 2% de probabilité de janvier 09 à décembre 10 : -64,0 TWh
- moyens requis : 64 TWh

D- Moyens identifiés pour couvrir le scénario de déficit de 64 TWh avant le 1er mai 2011

	2009 (>1er mai) – 2010 – 2011 (<1er mai) (TWh)
→ Réduction du stock énergétique (jusqu'au minimum opérationnel absolu de 10 TWh)	60,8
→ Production disponible non engagée (marge de manœuvre)	27,7 (8+15+5)
→ Exploitation de la Centrale de Tracy (note 1)	non requise
→ Importations (en sus de HQ-D, le cas échéant)	non requises
→ Total – moyens identifiés (note 2)	88,5 TWh

Note 1 : La production de la centrale de Tracy reste limitée à la période de pointe hivernale sur l'horizon de ce scénario.

Note 2 : Les moyens identifiés (88,5 TWh) excèdent les besoins spécifiques du scénario de faible hydraulicité à 2% de probabilité sur 2 années consécutives (64 TWh).

Novembre 2008

Hydro-Québec Production – État des réserves et de la fiabilité énergétique

Critère de gestion – 4 ans à 2% de probabilité (-98 TWh) – Cycle des années 2009-12

A- Stock énergétique au 1er janvier 2009 (prévu) : 114,3 TWh

B- Stock énergétique prévu au 1er mai 2013 à hydraulicité normale de 2009 à 2012 : 69,7 TWh

C- Application du critère de gestion :

- cycle de faible hydraulicité à 2% de probabilité de janvier 09 à décembre 12 : -98,0 TWh
- moyens requis : 98 TWh

D- Moyens identifiés pour couvrir le scénario de déficit de 98 TWh avant le 1er mai 2013

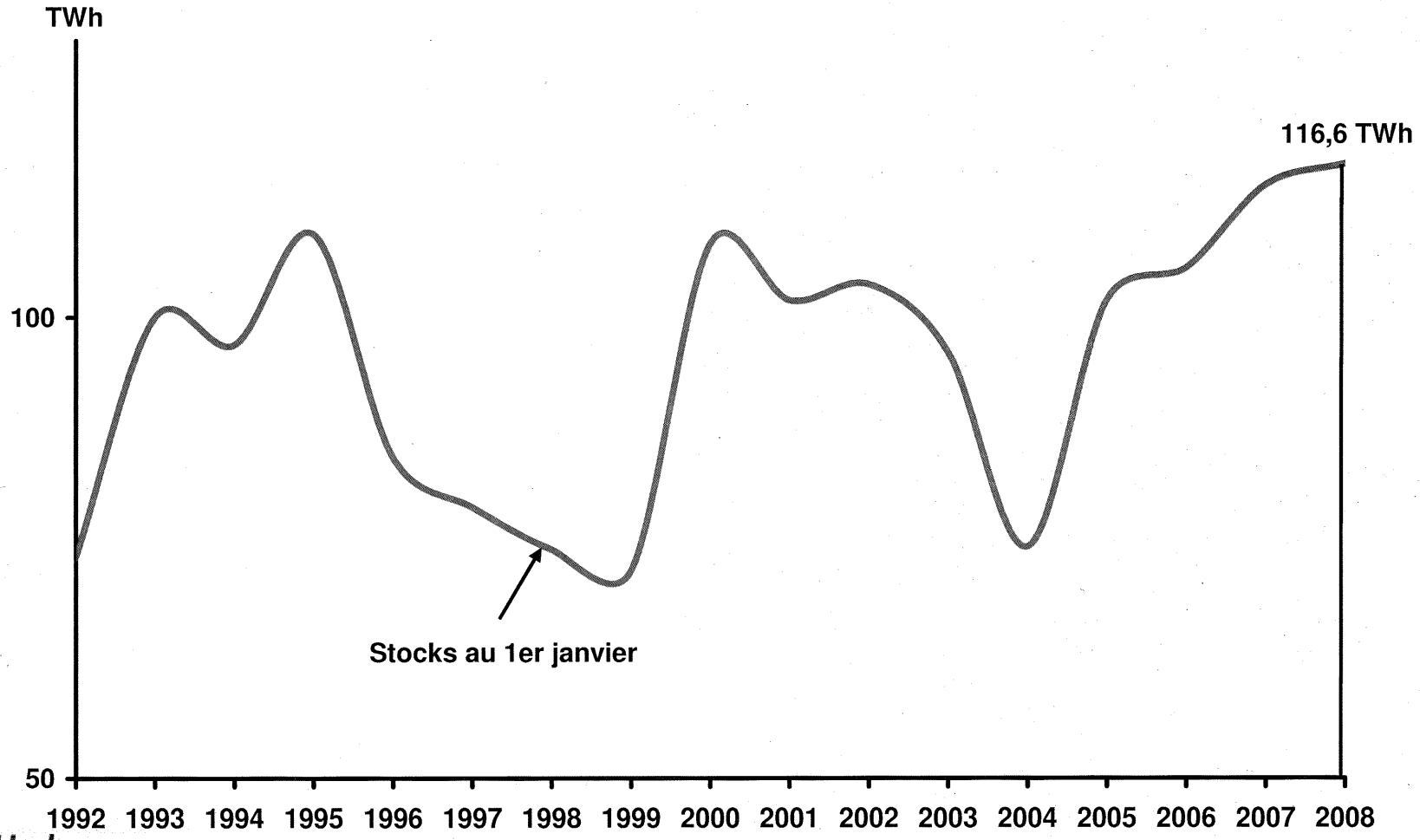
	2009 (>1er mai) – 2013 (<1er mai) (TWh)	
→ Réduction du stock énergétique (jusqu'au minimum opérationnel absolu de 10 TWh)	59,7	
→ Production disponible non engagée (marge de manœuvre)	60,9	(8+15+15+16+7)
→ Exploitation de la Centrale de Tracy (note 1)	non requise	
→ Importations (en sus de HQ-D, le cas échéant)	non requises	
→ Total – moyens identifiés (note 2)	120,6 TWh	

Note 1 : La production de la centrale de Tracy reste limitée à la période de pointe hivernale sur l'horizon de ce scénario.

Note 2 : Les moyens identifiés (120,6 TWh) excèdent les besoins spécifiques du scénario de faible hydraulicité à 2% de probabilité sur 4 années consécutives (-98 TWh).

Novembre 2008

Stocks énergétiques
Historique 1992 - 2008

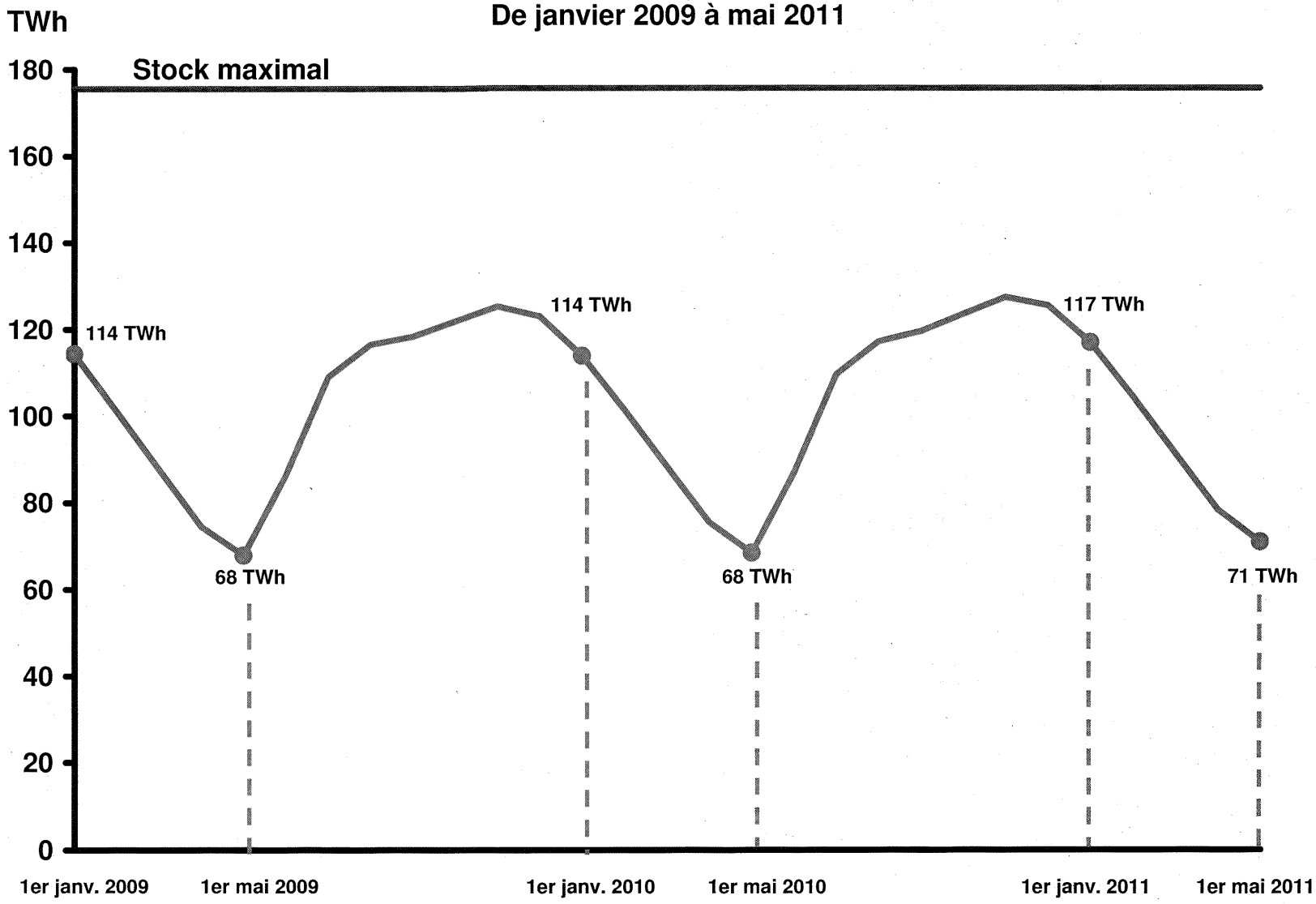


Hydro Québec

2008-05-13

ÉVOLUTION DU STOCK ÉNERGÉTIQUE

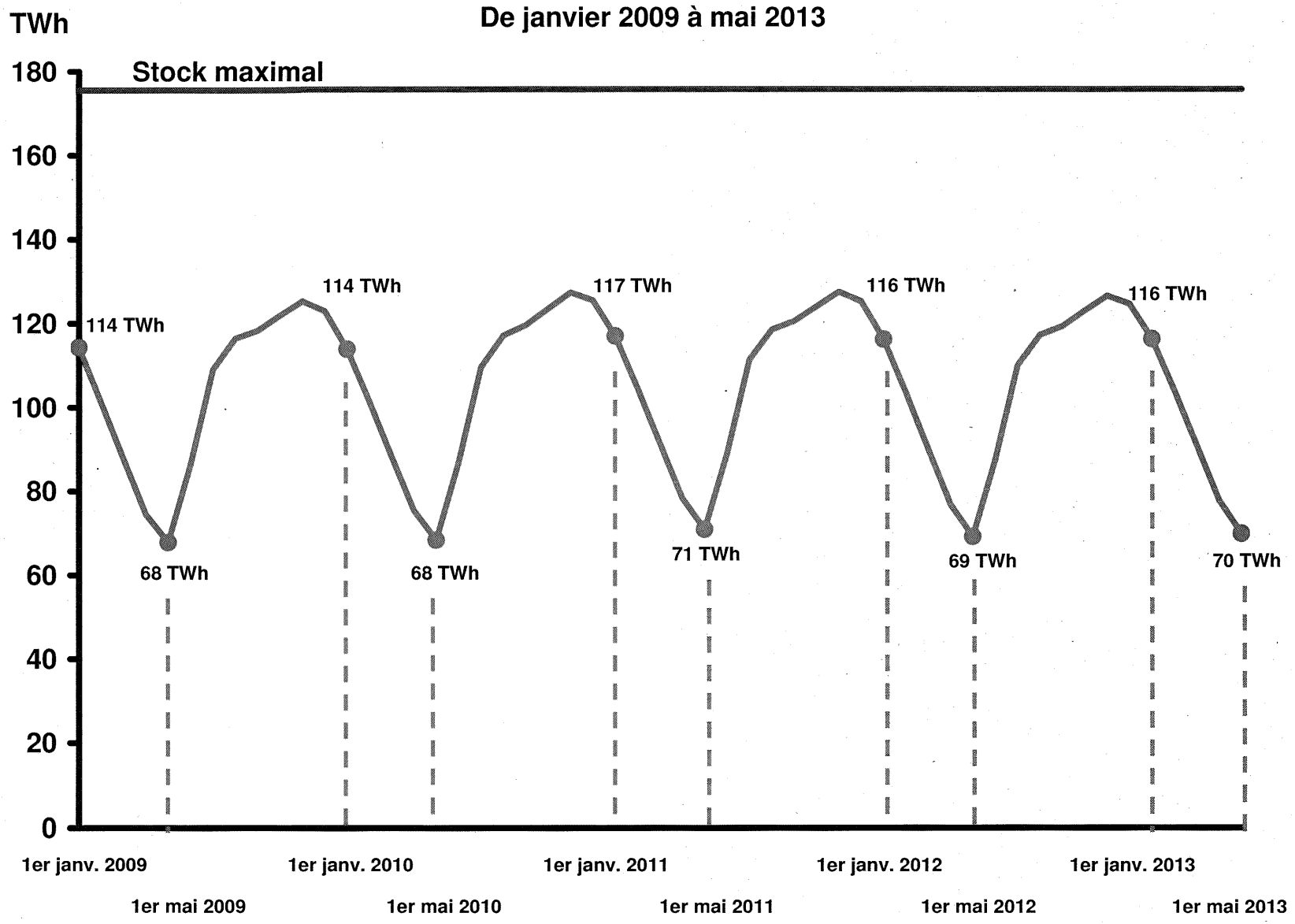
De janvier 2009 à mai 2011



2008-11-18

ÉVOLUTION DU STOCK ÉNERGÉTIQUE

De janvier 2009 à mai 2013



2008-11-18

ANNEXE D

RESPECT DU CRITÈRE DE FIABILITÉ EN PUISSANCE
BILAN DU DISTRIBUTEUR
POUR L'ANNÉE 2008-2009
EN MW

ANNEXE D
Respect du critère de fiabilité en puissance
Bilan du Distributeur pour l'année 2008-2009
en MW

	Pointe 2008/2009
Besoins à la pointe visés par le plan	**36 040**
+ Réserve requise du Distributeur	3 485
= Ressources requises	**39 525**
- Approvisionnements existants et à venir	**39 183**
Électricité patrimoniale	34 342
Réserve sur électricité patrimoniale	3 100
Électricité interruptible	735
TransCanada Energy	0
Hydro-Québec Production - Base	350
Hydro-Québec Production - Cyclable	250
Contrats de biomasse (incluant Tembec)	44
Contrats Éoliens (après entente d'intégration)	112
Abaissement de tension	250
= Puissance additionnelle requise	**342**

ANNEXE F

LETTRE D'ATTESTATION DE LA FIABILITÉ ÉNERGÉTIQUE DU PARC DE PRODUCTION D'HYDRO-QUÉBEC PRODUCTION

Hydro Québec

Le 8 décembre 2008

Thierry Vandal
Président-directeur général

Hydro-Québec
75, boulevard René-Lévesque Ouest
20e étage
Montréal (Québec) H2Z 1A4

Monsieur Jean-Paul Théorêt
Président
Régie de l'énergie
800, place Victoria
Bureau 255
Montréal (Québec) H4Z 1A2

OBJET : Suivi de la décision D-2008-133 de la Régie de l'énergie
Attestation de fiabilité énergétique du parc de production

Monsieur le Président,

Dans sa décision D-2008-133 du 20 octobre 2008 relative au *Plan d'approvisionnement 2008-2017 d'Hydro-Québec*, la Régie de l'énergie fait référence au critère de fiabilité en énergie applicable au volume d'électricité fourni par Hydro-Québec Production, à savoir le maintien d'une réserve énergétique suffisante pour combler un déficit éventuel d'apport d'eau de 64 TWh sur deux années consécutives et de 98 TWh sur quatre années consécutives. La Régie a demandé à Hydro-Québec Distribution de vérifier le respect de ce critère auprès de son fournisseur, de déposer et de rendre publique, en mai, août et novembre de chaque année, la démonstration de ce respect.

Ayant eu une présentation de la situation des stocks énergétiques, je suis satisfait quant au respect des critères de fiabilité en énergie applicables au volume d'électricité fourni par Hydro-Québec Production et au fait que cette dernière dispose du stock énergétique pour livrer à Hydro-Québec Distribution le volume d'électricité engagé pour la période 2009-2010.

Les critères de fiabilité en énergie applicables au volume d'électricité concerné sont respectés, sans l'utilisation d'importations et sans recourir à une exploitation accrue de la centrale de Tracy, laquelle sera limitée aux périodes de pointe hivernale.

Je vous prie d'agréer, Monsieur le Président, l'expression de mes sentiments distingués.

Thierry Vandal

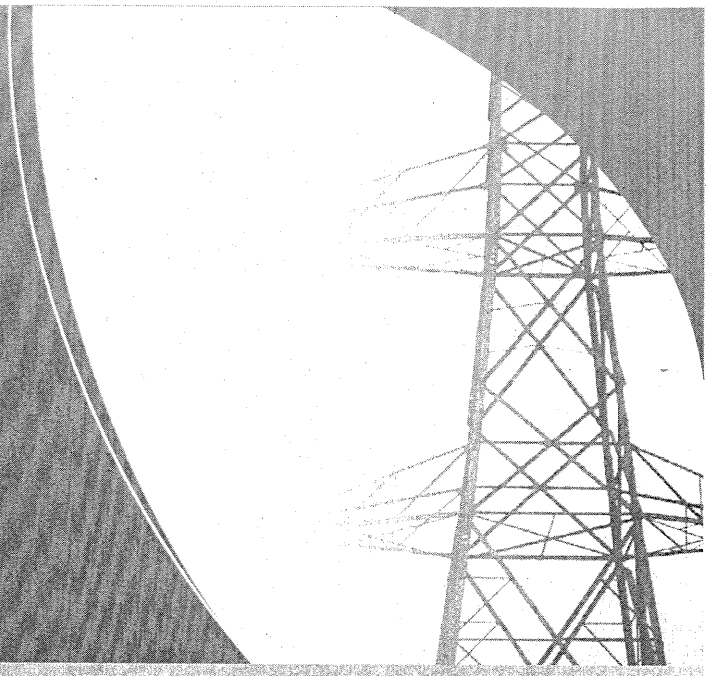
p.j.

ANNEXE G

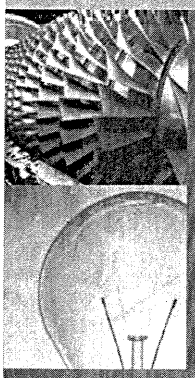
EXTRAITS DU 2008-2009 WINTER RELIABILITY ASSESSMENT DU NERC

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



2008/2009 Winter Reliability Assessment



the reliability of the bulk power system

November 2008

116-390 Village Blvd., Princeton, NJ 08540
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www.nerc.com

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Resources, Demand and Capacity Margins

To improve consistency and increase the granularity/transparency of how regional resource projections are represented in NERC assessment reports, NERC's Planning Committee approved new categories for capacity resources and capacity purchases and sales (see Table 3). The categories of "committed" and "uncommitted" resource designations used in the 2007/2008 Winter Reliability Assessment are now replaced with the following:

1. **Existing**
   a) Certain — Existing capacity resources reasonably anticipated to be available and operate and that are deliverable to or into the region.
   b) Uncertain — Includes mothballed generation and portions of variable generation not included in "Certain"

2. **Planned** — Capacity resources expected to be available for the 2008/2009 Winter that have achieved one or more of the following milestones:
   a) Construction has started
   b) Regulatory permits approved
   c) Approved by corporate or appropriate senior management

3. **Capacity Purchases and Sales** – the following categories may be applied to existing and future capacity calculations.
   a) Firm
   b) Non-Firm
   c) Expected
   d) Provisional

See the section entitled *"Reliability Concepts Used in this Report"* for more detailed definitions.

Table 3: Capacity Resources & Margins

Net Internal Demand (MW) —Total Internal Demand reduced by dispatchable controllable (capacity) demand response

Total Internal Capacity (MW) — The Sum of Existing (both Certain and Uncertain) and Planned Capacity.

Existing-Certain Capacity and Net Firm Transactions (MW) — Existing capacity resources reasonably anticipated to be available and operate and that are deliverable to or into the region plus net Firm Purchases/Sales.

Net Capacity Resources (MW) — Total Internal Capacity, less Transmission-Limited Resources, all Derates, Energy Only, and Inoperable resources; plus net Firm, Expected and Provisional Purchases/Sales. Net Capacity Resources do not include Non-Firm Purchases/Sales.

Total Potential Resources (MW) — Total Internal Capacity, less Transmission-Limited Resources plus the net of all Purchases/Sales.

Existing Certain Capacity and Net Firm Transactions Margin (%) — Existing-Certain Capacity and Net Firm Transactions less Net Internal Demand shown as a percent of Existing Certain Capacity and Net Firm Transactions.

Net Capacity Resources Margin (%) — Net Capacity Resources reduced by the Net Internal Demand; shown as a percent of Net Capacity Resources.

Total Potential Resources Margin (%) — Total Potential Resources reduced by the Net Internal Demand; shown as a percent of Total Potential Resources.

NERC Reference Margin Level (%) — Either the Target Capacity Margin provided by the region/sub-region or NERC assigned based on capacity mix (i.e. thermal/hydro)

Data gathered using the improved resource categories were used to develop capacity margins for trending and comparative assessment. Table 4a through 4c provides a month-by-month summary of 2008/2009 winter resources, demand and capacity margins.

Projected 2008/2009 Winter Margins

Capacity margins, reflecting existing resources reasonably anticipated to be available to operate and deliver power to or into the region, along with firm capacity purchases, appear to be higher then the NERC Reference Margin Levels for the 2008/2009 winter months (Figures 12a-12b).

Figure 12a: NERC U.S. – 2008/2009 Winter Capacity Margins

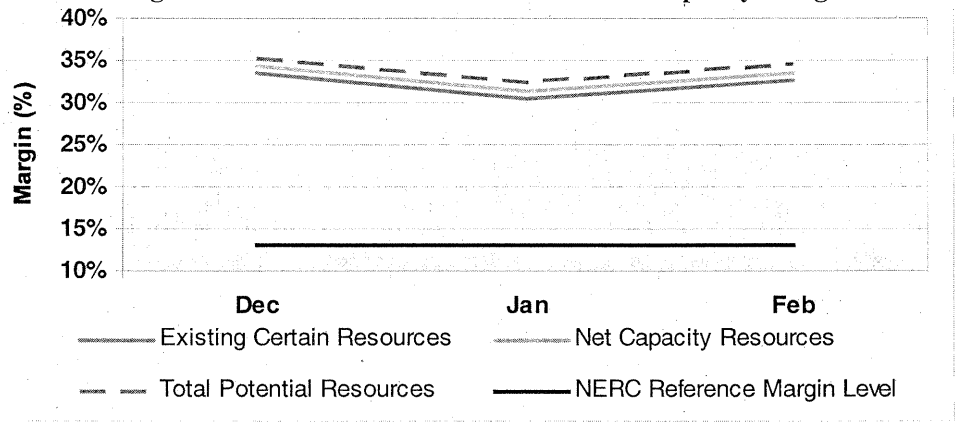


Figure 12b: NERC CAN – 2008/2009 Winter Capacity Margins

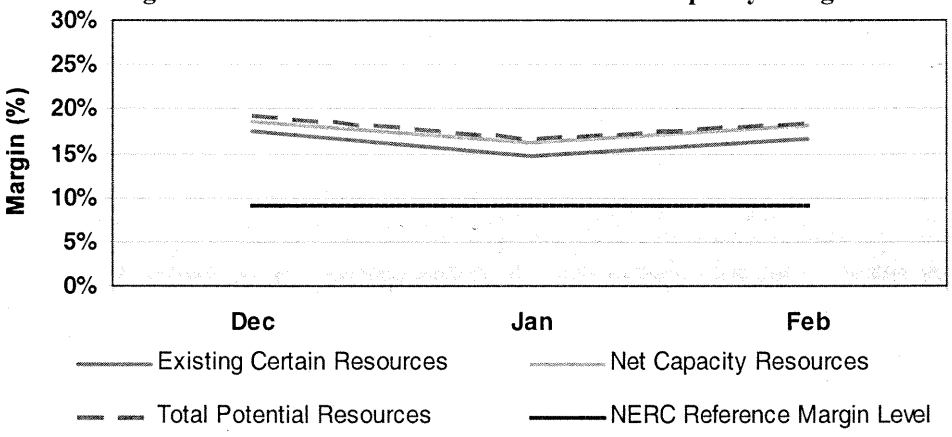


Table 4a: Estimated December 2008 Capacity Margins, Resources and Demands

December 2008

	Net Internal Demand (MW)	Existing Certain Capacity & Net Firm Transactions (MW)	Net Capacity Resources (MW)	Total Potential Resources (MW)	Existing Certain Capacity and Net Firm Transactions Margin (%)	Net Capacity Resources Margin (%)	Total Potential Resources Margin (%)	NERC Reference Margin Level (%)
United States								
ERCOT	40,185	73,980	74,877	74,884	45.7	46.3	46.3	11.1
FRCC	37,303	57,891	57,963	57,963	35.6	35.6	35.6	13.0
MRO	33,758	46,757	47,521	48,120	27.8	29.0	29.8	13.0
NPCC	43,921	74,465	75,013	74,352	41.0	41.4	40.9	
New England	20,176	33,303	33,453	32,792	39.4	39.7	38.5	13.0
New York	23,745	41,162	41,560	41,560	42.3	42.9	42.9	13.0
RFC	140,600	211,000	211,000	215,422	33.4	33.4	34.7	
RFC-MISO	47,223	66,200	66,200	70,552	28.7	28.7	33.1	12.8
RFC-PJM	93,300	142,500	142,500	142,570	34.5	34.5	34.6	12.8
SERC	164,514	236,539	237,264	237,212	30.4	30.7	30.6	
Central	38,877	46,806	46,711	46,711	16.9	16.8	16.8	13.0
Delta	21,058	35,649	36,469	36,469	40.9	42.3	42.3	13.0
Gateway	14,903	23,761	23,761	23,761	37.3	37.3	37.3	13.0
Southeastern	37,199	57,679	57,679	57,679	35.5	35.5	35.5	13.0
VACAR	52,477	72,644	72,644	75,436	27.8	27.8	30.4	13.0
SPP	30,217	49,107	50,223	59,218	38.5	39.8	49.0	13.0
WECC	113,368	164,022	165,402	165,417	30.9	31.5	31.5	12.1
AZ-NM-SNV	18,946	34,964	35,404	35,404	45.8	46.5	46.5	11.7
CA-MX US	42,928	60,101	60,126	60,126	28.6	28.6	28.6	13.3
NWPP	41,096	55,570	56,290	56,306	26.0	27.0	27.0	11.9
RMPA	10,398	13,480	13,675	13,675	22.9	24.0	24.0	10.5
Total-United States	**603,866**	**913,762**	**919,263**	**932,588**	**33.9**	**34.3**	**35.2**	**13.0**
Canada								
MRO	7,383	8,647	8,658	8,658	14.6	14.7	14.7	9.1
NPCC	59,747	74,267	75,405	76,237	19.6	20.8	21.6	
Maritimes	4,808	6,971	6,971	6,971	31.0	31.0	31.0	13.0
Ontario	22,614	27,730	28,786	29,584	18.4	21.4	23.6	14.5
Quebec	32,325	39,566	39,648	39,682	18.3	18.5	18.5	9.1
WECC	21,185	24,005	24,457	24,457	11.7	13.4	13.4	10.2
Total-Canada	**88,315**	**106,919**	**108,520**	**109,352**	**17.4**	**18.6**	**19.2**	**9.1**
Mexico								
WECC CA-MX Mex	1,530	2,191	2,191	2,191	30.2	30.2	30.2	12.5
Total-NERC	**693,711**	**1,022,872**	**1,029,974**	**1,044,131**	**32.2**	**32.6**	**33.6**	**13.0**

Table 4b: Estimated January 2009 Capacity Margins, Resources and Demands

January 2009	Net Internal Demand (MW)	Existing Certain Capacity & Net Firm Transactions (MW)	Net Capacity Resources (MW)	Total Potential Resources (MW)	Existing Certain Capacity & Net Firm Transactions Margin (%)	Net Capacity Resources Margin (%)	Total Potential Resources Margin (%)	NERC Reference Margin Level (%)
United States								
ERCOT	45,658	73,980	74,877	74,884	38.3	39.0	39.0	11.1
FRCC	46,093	57,248	57,319	57,319	19.5	19.6	19.6	13.0
MRO	34,067	46,703	47,557	48,149	27.1	28.4	29.2	13.0
NPCC	44,766	74,968	75,516	76,128	40.3	40.7	41.2	
New England	21,021	33,806	33,956	34,568	37.8	38.1	39.2	13.0
New York	23,745	41,162	41,560	41,560	42.3	42.9	42.9	13.0
RFC	140,900	211,000	211,000	215,422	33.2	33.2	34.6	
RFC-MISO	44,903	66,200	66,200	70,552	32.2	32.2	36.4	12.8
RFC-PJM	95,900	142,500	142,500	142,570	32.7	32.7	32.7	12.8
SERC	177,929	240,277	241,002	240,983	25.9	26.2	26.2	
Central	41,857	48,860	48,765	48,765	14.3	14.2	14.2	13.0
Delta	24,406	35,649	36,469	36,469	31.5	33.1	33.1	13.0
Gateway	14,965	24,897	24,897	24,897	39.9	39.9	39.9	13.0
Southeastern	40,462	57,819	57,819	57,819	30.0	30.0	30.0	13.0
VACAR	56,239	73,052	73,052	73,072	23.0	23.0	23.0	13.0
SPP	31,146	49,107	50,223	59,218	36.6	38.0	47.4	13.0
WECC	111,600	161,108	163,260	163,296	30.7	31.6	31.7	12.1
AZ-NM-SNV	18,675	34,220	35,073	35,074	45.4	46.8	46.8	11.7
CA-MX US	41,277	58,518	58,556	58,556	29.5	29.5	29.5	13.3
NWPP	41,528	55,223	56,123	56,158	24.8	26.0	26.1	11.9
RMPA	10,120	13,240	13,601	13,601	23.6	25.6	25.6	10.5
Total-United States	**632,159**	**915,144**	**920,754**	**935,399**	**30.9**	**31.3**	**32.4**	**13.0**
Canada								
MRO	7,472	8,661	8,672	8,672	13.7	13.8	13.8	9.1
NPCC	63,088	74,584	75,974	76,524	15.4	17.0	17.6	
Maritimes	5,092	7,051	7,051	7,151	27.8	27.8	28.8	13.0
Ontario	23,167	28,192	29,500	29,916	17.8	21.5	22.6	14.5
Quebec	34,829	39,341	39,423	39,457	11.5	11.7	11.7	9.1
WECC	20,909	23,998	24,547	24,547	12.9	14.8	14.8	10.2
Total-Canada	**91,469**	**107,243**	**109,193**	**109,743**	**14.7**	**16.2**	**16.7**	**9.1**
Mexico								
WECC CA-MX Mex	1,481	1,977	1,977	1,977	25.1	25.1	25.1	12.5
Total-NERC	**725,109**	**1,024,364**	**1,031,924**	**1,047,119**	**29.2**	**29.7**	**30.8**	**13.0**

Table 4c: Estimated February 2009 Capacity Margins, Resources and Demands

February 2009	Net Internal Demand (MW)	Existing Certain Capacity & Net Firm Transactions (MW)	Net Capacity Resources (MW)	Total Potential Resources (MW)	Existing Certain Capacity & Net Firm Transactions Margin (%)	Net Capacity Resources Margin (%)	Total Potential Resources Margin (%)	NERC Reference Margin Level (%)
United States								
ERCOT	46,211	73,980	74,877	74,884	37.5	38.3	38.3	11.1
FRCC	46,362	57,248	57,510	57,510	19.0	19.4	19.4	13.0
MRO	33,312	46,652	47,506	48,105	28.6	29.9	30.8	13.0
NPCC	44,153	70,565	71,113	76,143	37.4	37.9	42.0	
New England	20,408	29,403	29,553	34,583	30.6	30.9	41.0	13.0
New York	23,745	41,162	41,560	41,560	42.3	42.9	42.9	13.0
RFC	134,800	211,000	211,000	215,422	36.1	36.1	37.4	
RFC-MISO	42,664	66,200	66,200	70,552	35.6	35.6	39.5	12.8
RFC-PJM	92,100	142,500	142,500	142,570	35.4	35.4	35.4	12.8
SERC	166,157	240,117	240,842	240,823	30.8	31.0	31.0	
Central	39,553	48,822	48,727	48,727	19.0	18.8	18.8	13.0
Delta	21,707	35,634	36,454	36,454	39.1	40.5	40.5	13.0
Gateway	13,482	24,843	24,843	24,843	45.7	45.7	45.7	13.0
Southeastern	37,811	57,835	57,835	57,835	34.6	34.6	34.6	13.0
VACAR	53,604	72,983	72,983	73,333	26.6	26.6	26.9	13.0
SPP	30,370	49,107	50,223	59,218	38.2	39.5	48.7	13.0
WECC	107,804	157,070	159,220	159,256	31.4	32.3	32.3	12.1
AZ-NM-SNV	17,795	33,005	33,858	33,859	46.1	47.4	47.4	11.7
CA-MX US	40,108	56,051	56,089	56,089	28.4	28.5	28.5	13.3
NWPP	39,846	54,977	55,875	55,910	27.5	28.7	28.7	11.9
RMPA	10,055	13,130	13,491	13,491	23.4	25.5	25.5	10.5
Total-United States	**609,169**	**905,739**	**912,291**	**931,361**	**32.7**	**33.2**	**34.6**	**13.0**
Canada								
MRO	7,260	8,644	8,655	8,655	16.0	16.1	16.1	9.1
NPCC	60,851	74,092	75,482	75,938	17.9	19.4	19.9	
Maritimes	5,109	7,154	7,154	7,154	28.6	28.6	28.6	13.0
Ontario	22,668	27,737	29,045	29,467	18.3	22.0	23.1	14.5
Quebec	33,074	39,201	39,283	39,317	15.6	15.8	15.9	9.1
WECC	20,325	23,276	23,829	23,829	12.7	14.7	14.7	10.2
Total-Canada	**88,436**	**106,012**	**107,966**	**108,422**	**16.6**	**18.1**	**18.4**	**9.1**
Mexico								
WECC CA-MX Mex	1,459	1,837	1,837	1,837	20.6	20.6	20.6	12.5
Total-NERC	**699,064**	**1,013,588**	**1,022,094**	**1,041,620**	**31.0**	**31.6**	**32.9**	**13.0**

Notes for Table 4a through 4c

Note 1: Existing-Certain and Net Firm Transactions and Net Capacity Resources are reported to be deliverable by the regions.

Note 2: The Inoperable portion of Total Potential Resources may not be deliverable.

Note 3: The WECC-U.S. peak demands or resources do not necessarily equal the sums of the non-coincident WECC-U.S. subregional peak demands or resources because of subregional monthly peak demand diversity. Similarly, the Western Interconnection peak demands or resources do not necessarily equal the sums of the non-coincident WECC-U.S., Canada, and Mexico peak demands or resources. Also, the subregional resource numbers include utilization of seasonal demand diversity between the winter peaking northwest and the summer peaking portions of the Western Interconnection.

Note 4: The demand side management resources are not necessarily sharable between the WECC subregions and are not necessarily sharable within subregions.

Note 5: WECC CA-MX represents only the northern portion of the Baja California Norte, Mexico electric system interconnected with the U.S.

Note 6: MISO and PJM information does not sum to the RFC total as approximately 100 MW of Ohio Valley Electric Corporation (OVEC)[25] peak demand. OVEC is not affiliated with either PJM or MISO; however, OVEC's Reliability Coordinator services are performed by PJM. RFC information is only for the demand and capacity within its region.

Note 7: These demand and supply forecasts are as of September 30, 2008.

Note 8: Each region/subregion may have their own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the regional/subregional Target Capacity Margin level is adopted as the NERC Reference Margin Level. If not, NERC assigned 13% capacity margin for predominately thermal systems and 9% for predominately hydro systems.

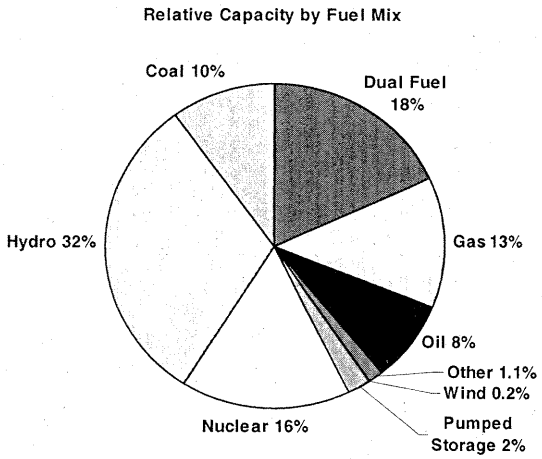
[25] OVEC is a generation and transmission utility located in Indiana, Kentucky and Ohio.

NPCC

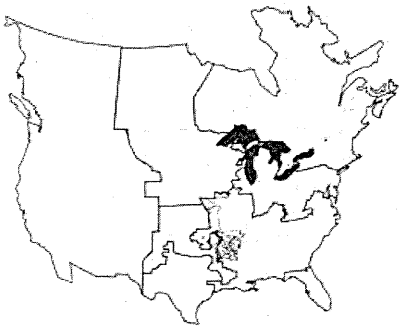
2008/09 Projected Winter Peak Demand	MW
Total Internal Demand	113,936
Direct Control Load Management	250
Contractually Interruptible (Curtailable)	2,003
Critical Peak-Pricing with Control	0
Load as a Capacity Resource	3,829
Net Internal Demand	107,854

	MW	Change
2007/08 Actual Winter Peak Demand	110,314	-2.2%
All-Time Winter Peak Demand	115,099	-6.3%

2008/09 Projected Winter Capacity	MW	Capacity Margin
Existing Certain and Net Firm Transactions	145,249	25.7%
Net Capacity Resources	147,187	26.7%
Total Potential Resources	152,652	29.3%



Introduction



For the 2008/2009 winter operating period, each NPCC Area meets the NPCC resource adequacy criterion which states that probability of disconnecting firm load shall be not more than once in ten years. When compared with projections for the 2007/2008 winter, each Area is also projecting a margin which exceeds that projected for the 2007/2008 winter.

No operational problems are anticipated during the winter peak load period, and the transmission system is expected to perform adequately. No disruptions of fuel supply are predicted in any of the NPCC Areas. In particular, current gas industry projections indicate that, going into the winter season, full storage of natural gas supply will have been achieved, and no long term damage to the natural gas supply infrastructure was sustained during the tropical storms experienced by the Gulf of Mexico in the late summer.

The five NPCC Areas, or subregions, are defined by the following footprints:

- the Maritimes Area (the New Brunswick System Operator, Nova Scotia Power Inc., the Maritime Electric Company Ltd. and the Northern Maine Independent System Administrator, Inc);
- New England (the ISO New England Inc.);
- New York (New York ISO);
- Ontario (Independent Electricity System Operator); and
- Québec (Hydro-Québec TransÉnergie).

The Maritimes Area and the Québec Area are winter peaking systems; Ontario, New York and New England are summer peaking systems. Through numerous studies and reviews, the NPCC Task Force on Coordination of Planning (TFCP) will ensure that the proposed resources of each NPCC Area will comply with NPCC Document A-02, "Basic Criteria for Design and Operation of Interconnected Power Systems (http://www.npcc.org/documents/regStandards/Criteria.aspx)." Section 3.0 of Document A-02 defines the criterion for resource adequacy for each Area as follows:

> **Resource Adequacy - Design Criteria**
>
> Each **Area's** probability (or risk) of disconnecting any **firm load** due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the **loss of load expectation** [**LOLE**] of disconnecting **firm load** due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring **Areas** and **Regions**, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

These assessments of resource compliance are complemented by the efforts of the Working Group on the Review of Resource and Transmission Adequacy (Working Group CP-08), which assesses the interconnection benefits assumed by each NPCC Area in demonstrating compliance with the NPCC resource reliability. The Working Group conducts such studies at least triennially for a window of five years, and the Working Group determines that the outside assistance assumed by each Area is reasonable.

Subregions

Maritimes

Peak Demand and Energy
The Maritimes Area is a winter peaking system. The Maritimes Area load is the mathematical sum of the forecasted weekly peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). As such, it does not take the effect of load coincidence within the week into account. Economic assumptions are not made when determining load forecasts.

Based on the Maritimes Area 2008/2009 demand forecast, a peak of 5,547 MW is predicted to occur for the winter period, December through February. The actual peak for Winter 2007/2008 was 5,385 MW on January 22, 2008, which was approximately 142 MW (2.6%) lower than last year's forecast of 5,527 MW and was 160 MW (2.9%) lower than this year's winter forecast. The reduction in demand was due to higher than forecasted temperatures, resulting in a lower electric heating load and shutdowns of industrial load.

Québec

Peak Demand and Energy
In 2007 Hydro-Québec introduced a new weather pattern in its load forecast which is based on the average climatic conditions observed from 1971 to 2006 adjusted for a global warming effect of 0.30°C per decade starting in 1971.

The 2008/2009 winter projected peak internal demand is 36,379 MW. This forecast is approximately the same as last year's forecast for the 2007/2008 winter (36,361 MW).

Total Internal Demand in MW

	December	January	February
Actual 07/08	33,389	35,352	33,203
Forecasted 08/09	33,875	36,379	34,624
Difference	486	1,027	1,421

The forecast for 2008/2009 winter is 2.9% higher than the 2007/2008 winter actual peak.

Last year's winter weather was generally milder than normal, so that electric space heating demand has been lower than expected. Due to high heating oil and natural gas prices, more conversion to electric space heating is expected this year compared to last year.

There is only one load serving entity in Québec so there is no demand aggregating.

There are two interruptible load programs in Québec. Each program has its own customers, large high voltage industrial customers for the Hydro-Québec Production program (Aluminium and iron smelters) and smaller industrial customers for the Hydro-Québec Distribution program (Paper mills and chemical industries). The HQP program totals 791 MW most of which cannot be called twice a day, so that for planning purposes, a factor is applied for operational constraints. The HQD program totals 800 MW and a factor for operational constraints is also applied for planning purposes. Therefore, the following numbers are applied to Area reliability analyses: Hydro-Québec Production (HQP) : 350 MW; and Hydro-Québec Distribution (HQD) : 680 MW. Moreover, the Québec Balancing Authority Area can rely on 250 MW of direct control load management in the form of voltage reduction.

Climatic uncertainty is modeled by recreating each hour of the 36-year period of climatic conditions (1971 through 2006) under the current load forecast conditions. Moreover, each year of historical data is shifted up to ± 3 days to gain information on conditions that occurred during a weekend for example. Such an exercise generates a set of 252 different hourly load scenarios. The arithmetic average of these 252 scenarios is the normal weather forecast. The standard deviation analysis at winter peak gives the climatic uncertainty at peak time; this is more than 4 % of the normal weather forecast.

The assessment of the demand forecast uncertainty under normal weather conditions is done by taking into account the realization of high and low demand scenarios. These scenarios are driven by economic and demographic parameters. Statistical simulations of these parameters lead to different possible outcomes. The demand forecast uncertainty – measured by a standard deviation analysis – is about near 2% of the base case scenario for the first year of forecasting. Incidentally, for this same year, the high case demand scenario is 2% higher than the base case scenario.

Finally, a global demand uncertainty for the winter peak, which is the independent combination of demand forecast uncertainty and weather uncertainty, is then obtained. This global uncertainty – measured by a standard deviation analysis – is near 5 % of the base case scenario for the first year of forecasting.

Generation (Resource Adequacy Assessment)
For the 2008/2009 winter period the Québec Balancing Authority expects 42,129 MW of existing capacity. Capacity classified by the NERC RAS as "Existing Certain" totals 39,796 MW; primarily from hydroelectric generation. Capacity classified by the NERC RAS as "Existing Uncertain" totals 2,333 MW. There is 471 MW of wind capacity but that is fully de-rated on peak for planning purposes. Biomass generation totals 211 MW. Planned capacity expected to be in service for the peak totals 82 MW and includes Chute-Allard (41 MW) and Rapides-des-Coeurs (41 MW) hydroelectric generation.

Hydro-Québec Distribution has negotiated with a private producer in Québec to shut down its natural gas unit (547 MW) for both 2008 and 2009.

Québec reservoir levels are sufficient to meet both peak demand and the daily energy demand throughout the winter. Currently, reservoir levels are higher than the expected mean levels. To assess its energy reliability Québec has developed an energy criterion that states that sufficient resources should be available to go through sequences of 2 or 4 consecutive years of low water inflows totaling 64 TWh and 98 TWh respectively and having a 2 % probability of occurrence. These assessments are presented three times a year to the Québec Energy Board. Hydro-Québec Distribution's 2009 energy consumption is expected to be about 184 TWh.

No fuel supply vulnerability studies are conducted in Québec beyond the normal assessment and management of reservoir water levels.

Non-hydraulic resources account for only a very small portion of total resources and are used for peaking purposes. Generating plants using heating oil or jet fuel are refueled by boat or by truck and generally not during the winter season.

Purchases and Sales on Peak
The Québec Balancing Authority Area does not need any external purchase for the 2008/2009 Winter Operating Period. Nevertheless, Hydro-Québec Production has a firm purchase of 200 MW from New Brunswick, which has been going on for a number of years during the Winter Operating Period.

There are no purchases (or external generation committed to an internal entity) from other regions or NPCC subregions that affect the Québec capacity margins. Furthermore, Liquidated Damage Contracts (LDCs) are not applicable.

Québec has two firm sales at peak backed by firm contracts transmission. These include one for 145 MW to Ontario and one for 310 MW to New England. The entire portion of these sales to Ontario and New England is backed by firm generation and transmission. As indicated above for purchases Liquidated Damage Contracts (LDCs) are also not applicable to sales. These firm sales do reduce the capacity margin but it still remains higher than the required margin.

Transmission Assessment

In 2009 TransÉnergie will be commissioning a new 2 X 625 MW back-to-back HVDC interconnection with the IESO in the Ottawa-Gatineau area across the Ottawa River. In preparation for this interconnection TransÉnergie is commissioning for the 2008/2009 peak period a new substation named "Outaouais". The AC sections of the station will be placed in-service during the first quarter of 2009. This station will be integrated into the existing 315 kV double-circuit line from Chénier in the Montréal area to Vignan in the Gatineau area. The Ontario side of the station is a 230 kV section fed by a double-circuit 230 kV line from Hawthorne substation in Ottawa. The HVDC interconnection is expected to be in service during the second quarter of 2009.

A new high voltage capacitor bank will be commissioned for the 2008/2009 peak period. This will be a 345 MVAr, 315 kV bank at Chénier.

Last year TransÉnergie was to commission the Lévis de-icing device. This has been postponed to this year because of commissioning problems. Part of this device will serve as a Static Var Compensator (-115 to +250 MVAr) to be used under normal system operation. The other part of the device will be used as a direct current generator (7,200 A at 25 kV) to eventually de-ice a specific number of 735 and 315 kV lines around the Lévis substation near Québec City. The Static VAr Compensator will be available for the 2008/2009 Winter Operating Period.

Several 230 kV transmission projects will integrate new hydro generation at Rapides-des-Coeurs and Chute-Allard as well as new wind generation at Carleton wind farm. These 230 kV projects have already been commissioned.

Operational Issues

Unit Outages

No generating unit outages are anticipated.

Transmission Outages

No transmission line outages are expected and no major maintenance is scheduled during the 2008/2009 Winter Operating Period that will significantly affect system operations. Some notes on expected outages include:

- Synchronous Condenser CS23 at Duvernay substation in the Montréal area is out of service until June 2009. This is due to a major transformer fault. The transformer must be replaced.

- The Némiscau 735/315 kV transformer mentioned in the winter 2007/2008 assessment has now been returned to service.

- One phase of transformer T8 at Micoua 735/315 kV substation failed on September 12, 2008 and must be replaced. This transformer station is situated in the Manicouagan sub-system and integrates generation from the Manicouagan, Toulnustouc and Outardes river systems (approximately 5,000 MW). Transformer T8 (570 MVA) is therefore out of service for the Winter Operating Period.

- Carignan 735/230 kV substation East of Montréal presently has one of its two transformers on forced outage. It will not be back in service for the 2008/2009 Winter Operating Period.

There are no environmental and/or regulatory restrictions that could impact reliability.

Reliability Assessment Analysis
The Québec Balancing Authority Area uses as its resource adequacy criterion a Loss of Load Expectation (LOLE) of 0.1 day/year thus requiring a 10 % reserve for the 2008/2009 winter peak period (Reserve Margin over Net Internal Demand). Each year, Triennial or Interim Reviews of Resource Adequacy and Long Term Multi-Area Probabilistic Reliability Assessments are prepared and presented to NPCC. Hydro-Québec Distribution must demonstrate its reliability to the Québec Energy Board and this assessment is done with the same tools and assumptions as those used in the NPCC resource adequacy assessments

In its review of resource adequacy for the NPCC, Québec includes a high load forecast scenario. The economic, demographic and energy parameters used for the study are set higher relative to the base case scenario. The load uncertainty then becomes dependent on weather conditions only. If the criterion (0.1 day/year of LOLE) is not met, actions to restore reliability are identified and established (new calls for tenders, new interruptible load contracts or an in service date for new generation units sooner than expected).

TransÉnergie performs load flow and stability studies on a continuous basis to assess system reliability and transfer capabilities on all its internal interfaces. A peak load study is performed annually integrating new generation, new transmission and the latest demand forecasts as well any operating conditions such as generation and transmission outages. Extreme cold weather conditions result in a large load pickup over the normal weather forecast and are included in the TransÉnergie Transmission Design Criteria. The Québec Area also participates in the seasonal NPCC CO-12 and CP-8 Working Group assessments of system reliability.

No particular operational problems have been observed for the oncoming winter 2008/2009 Winter Operating Period.

Required reserves, expressed as a peak load percentage, are about 10%. This percentage can vary if the future resources have different characteristics and/or the load uncertainty goes up.

The following table compares projected capacity margin between winter 2008/2009 and winter 2007/2008.

Projected Reserve Margins

Reserve Margin	January 2008	January 2009
In MW	4,464	4,594
In % of Net Internal Demand	12.7 %	13.2 %

Québec's electrical generation is mainly hydroelectric. The forced outage rates of hydraulic units are lower than for thermal units, so the margin required to meet the resource adequacy criterion is lower than the other NPCC's members. The NPCC resource adequacy criterion is 0.1 day/year of LOLE. With a capacity margin of 13.2 % the criterion is met.

The Québec system operator, TransÉnergie, designs and operates the transmission system within NERC and NPCC standards. The TransÉnergie Design Criteria documents are based on the NPCC A-2 document "Basic Criteria for Design and Operation of Interconnected Power System". In May 2008, NPCC approved the Comprehensive Review Assessment of the Québec Transmission System for 2012, based on compliance with the A-2 criteria and the corresponding NERC TPL standards. Every year, a comprehensive peak load study is performed in preparation for the upcoming peak load period in addition to any study addressing particular operating issues.

There are no internal transfer limits that impact reliability on the Québec system. Projected transmission margins for the peak period are adequate to carry the net internal demand plus the firm capacity sales and operating reserve. Moreover, enough transmission capability remains on the system to carry additional resources that would be called upon if load was greater than forecast.

Generation plants do not share common infrastructures other than the transmission grid. Therefore, no extreme contingencies are foreseeable other than a loss of transmission capacity. During the Winter Operating Period, the day-ahead capacity margin requirement is twice the operational reserve to account for load forecasting uncertainties and the availability of generating units. In Québec, 95 % of generation is hydroelectric. Energy (water) availability is more of a concern than capacity availability. To assess its energy reliability Québec has developed an energy criterion that states that sufficient resources should be available to go through sequences of 2 or 4 consecutive years of low water inflows totaling 64 TWh and 98 TWh respectively and having a 2 % probability of occurrence. These assessments are presented three times a year to the Québec Energy Board.

Québec uses the General Electric "MARS" model to perform its resource adequacy assessment. Internal transfer limits are taken into account in this model and no deliverability concerns are identified.

During each upcoming fall period, Hydro-Québec Distribution determines if capacity purchases are needed for the next winter period. This resource adequacy assessment is done using the same model and assumptions as for the NPCC resource adequacy review, except that only the Hydro-Québec Distribution part of demand and resources are considered in this study.

Hydro-Québec Production's fuel supply is not affected by extreme winter conditions during peak demand periods. Therefore, fuel deliverability problems are not anticipated. Since the vast majority of Hydro-Québec generation is hydroelectric, fossil fuel delivery is not a concern in Québec.

The following table indicates the interregional transfer capabilities out and into Québec with its neighboring systems for the 2008/2009 Winter Operating Period.[69]

Winter Interconnection Limits in MW

Interconnection	Limit out of Québec	Limit into Québec
Ontario North (D4Z, H4Z)	85	110
Ontario Ottawa (X2Y, P33C, Q4C)	410	140
Ontario Brascan	235	115
Ontario Beauharnois	800	470
New York (CD11, CD22)	325	100
New York (7040)	1,500 to 1,800	1,000
New England (Highgate)	220	170
New England (Stanstead-Derby)	50	0
New England (Sandy Pond)	1,200 to 2,000	1,700[70]
New Brunswick	1,100	770

These limits recognize transmission or generation constraints in both Québec and its neighbors. They are reviewed periodically with neighboring systems and are posted in the NPCC Reliability Assessments.

The Duvernay Synchronous Condenser outage, mentioned above, causes 100 to 400 MW of restrictions on three 735 kV interfaces on the system. The normal transfer capability on these interfaces is usually well over 10,000 MW so that this is not expected to significantly impact transmission reliability for the 2008/2009 Winter Operating Period.

[69] Limits obtained from the NPCC Reliability Assessment for Winter 2008/2009.
[70] Limit is 0 at peak load. Nicolet HVDC is used for internal transmission needs.

Limits imposed by the forced outage during the winter of the Micoua 735/315 kV transformer T8 may reduce by 100 to 200 MW the deliverable generating capacity of that substation. The situation is presently being assessed by TransÉnergie, but it is not expected to significantly impact reliability for the Winter Operating Period.

All new generating stations with an output greater than 100 MW must be equipped with static excitation systems and multi-band power system stabilizers (MBPSS). Multi-band stabilizers provide damping for various oscillation modes (both local and inter-area modes). Settings for all stabilizers are supplied by TransÉnergie based on small signal analysis to ensure adequate damping of each generating station.
Voltage support in the southern part of the system (load area) is a concern during the Winter Operating Period especially during episodes of heavy load. Hydro-Québec Production (the largest producer on the system) ensures that maintenance work on generators is finished by December 1, and that all possible generation is available. This, along with yearly testing of reactive capability of the generators, ensures maximum availability of both active and reactive power. The end of TransÉnergie maintenance work on the high voltage transmission system is also targeted for December 1. Also, TransÉnergie has a target for the availability of both high voltage and low voltage capacitor banks in the southern part of the system. No more than 200 MVAr of high voltage banks should be unavailable during the Winter Operating Period. The target for the low voltage banks is 90 % availability based on installed capacity in the load area of the system (5,531 MVAr).

Voltage variations on the high voltage transmission system are also of some concern. These are normal variations due to changes in transmitted power from north to south during load pickup and interconnection ramping. Under peak load conditions, these variations may be large enough to trigger the Automatic Shunt Reactor Switching System (French acronym: MAIS). TransÉnergie has recommended and undertaken a number of actions that will optimize shunt reactor switching such as:

- New software (operating tool) for the Montréal Area Voltage Control (French acronym: CTRM) at the Control Center
- Enhancement of reactive power control at Châteauguay Converters
- Optimization of the interconnection DC power ramping as a function of system conditions
- Study of dynamic shunt compensation additions in the Montréal Area for the 2011/2012 horizon

A total of 2,500 MW of UVLS is installed in Québec. It has been designed to operate following extreme contingencies involving the loss of two or more 735 kV lines tripped out in the load area of the system. UVLS operates on a pre-defined pool of load located in the Montréal area. No additional load has been assigned to UVLS in the last year.

Region Description

NPCC is a New York State not-for-profit membership corporation, the goal of which is to promote and enhance the reliable and efficient operation of the international, interconnected bulk power system in northeastern North America:

- *through the development of regional reliability standards and compliance assessment and enforcement of continent-wide and regional reliability standards, coordination of system planning, design and operations, and assessment of reliability; and*
- *through the establishment of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria.*

Geographically, the portion of NPCC within the United States includes the six New England states and the state of New York. The Canadian portion of NPCC includes the provinces of New Brunswick, Nova Scotia, Ontario and Québec. Approximately 45% of the net energy for load generated in NPCC is within the United States, and approximately 55% of the NPCC net energy for load is generated within Canada. Approximately 70% of the total Canadian load is within the NPCC Region. Geographically, the surface area of NPCC covers about 1.2 million square miles, and it is populated by more than 55 million people.

General Membership in NPCC is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of NERC, that has an interest in the reliable operation of the Northeastern North American bulk power system. Full Membership shall be available to entities which are General Members that also participate in electricity markets in the international, interconnected bulk power system in Northeastern North America. The Full Members of NPCC include independent system operators (ISO), regional transmission organizations (RTOs), Transcos and other organizations or entities that perform the Balancing Authority function operating in Northeastern North America. The current membership in NPCC totals fifty entities.

Among the Areas (subregions) of NPCC, Québec and the Maritimes are predominately winter peaking Areas; Ontario, New York and New England are summer peaking systems. (http://www.npcc.org/).

Abbreviations Used in this Report

AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (Subregion of WECC)
BCFD	Billion cubic feet per day
CA-MX-US	California-México (Subregion of WECC)
dc	Direct Current
DOE	U.S. Department of Energy
ECAR	East Central Area Reliability Coordination Agreement
EECP	Emergency Electric Curtailment Plan
ERO	Electric Reliability Organization
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse Gas
GRSP	Generation Reserve Sharing Pool
GTA	Greater Toronto Area
GWh	Gigawatt hours
HDD	Heating Degree Days
ICAP	Installed Capacity
IESO	Independent Electric System Operator (in Ontario)
IPSI	Integrated Power System Plan
IROL	Interconnection Reliability Operating Limit
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	Kilovolts (one thousand volts)
LFU	Load Forecast Uncertainty
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LSE	Load-serving Entities
LTRA	Long-Term Reliability Assessment
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MISO	Midwest Independent Transmission System Operator
MRO	Midwest Reliability Organization
MVA	Megavolt amperes
Mvar	Megavars
MW	Megawatts (millions of watts)
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool Area (subregion of WECC)
NYISO	New York Independent System Operator
OVEC	Ohio Valley Electric Corporation

PAR	Phase Angle Regulators
PC	NERC Planning Committee
PJM	PJM Interconnection
PRB	Powder River Basin
PRSG	Planned Reserve Sharing Group
RAS	Reliability Assessment Subcommittee of NERC Planning Committee
RCC	Reliability Coordinating Committee
RFC	Reliability*First* Corporation
RFP	Request For Proposal
RIS	Resource Issues Subcommittee of NERC Planning Committee
RMPA	Rocky Mountain Power Area (subregion of WECC)
RMR	Reliability Must Run
RRS	Reliability Review Subcommittee
RTO	Regional Transmission Organization
SCR	Special Case Resources
SERC	Southeastern Electric Reliability Council
SOL	System Operating Limit
SPP	Southwest Power Pool
SPS	Special Protection System
TCF	Trillion cubic feet
TRE	Texas Regional Entity
THI	Temperature Humidity Index
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
VACAR	Virginia and Carolinas (subregion of SERC)
WECC	Western Electricity Coordinating Council

Reliability Concepts Used in This Report

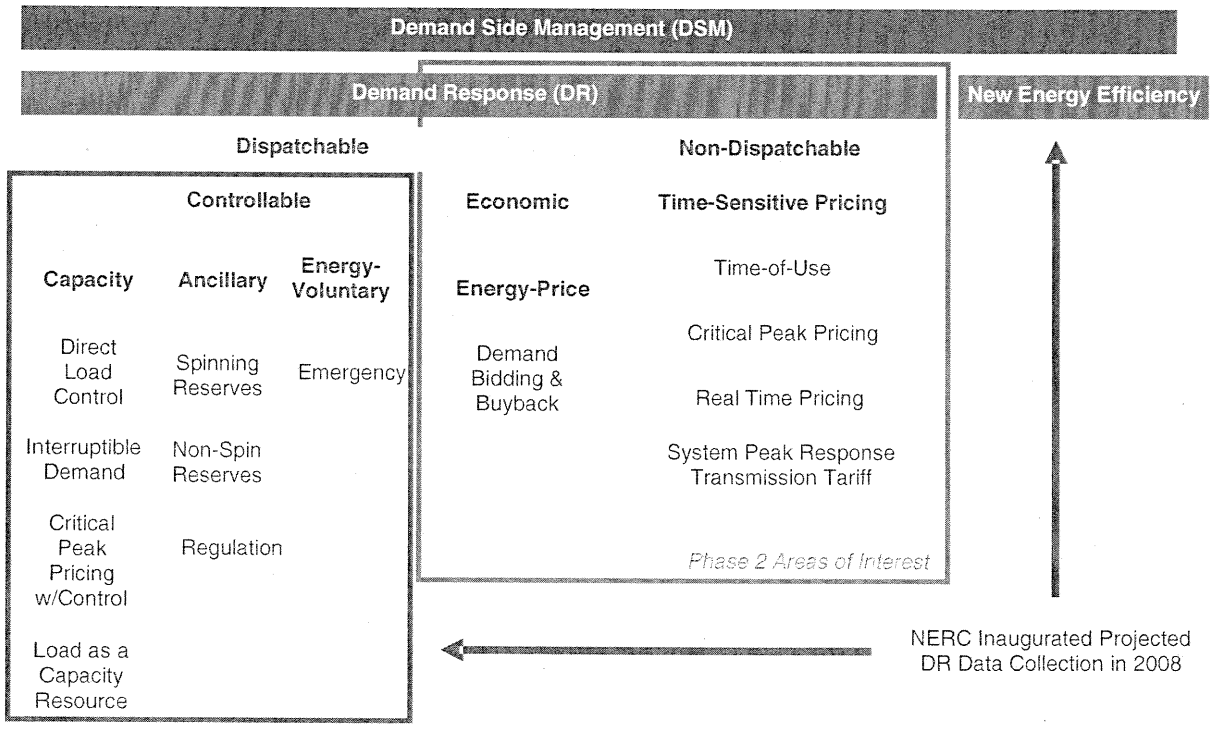
Demand Definitions

Total Internal Demand: Is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable demand response (such as Demand Bidding and Buy-Back).

Net Internal Demand: Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

Demand Response Categorization

Information about demand response categories in Phase 1 were collected for the 2008 Long Term Reliability Assessment. The figure below provides an overview of NERC's Demand-side management categories.



Demand-Side Management and NERC's Data Collection

Each of these is defined below:

Demand Response: changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized

Dispatchable: demand-side resource curtails according to instruction from a control center

Controllable: dispatchable demand response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints

Capacity: demand-side resource displaces or augments generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance

Direct Control Load Management: demand-side management that is under direct remote control of a control center. It is the magnitude of customer demand that can be interrupted at the time of the Regional Council seasonal peak by direct control of the System Operator by interrupting power supply to individual appliances or equipment on customer premises.

Contractually Interruptible (Curtailable): curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Council's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Critical Peak Pricing (CPP) with Control: demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Load as a Capacity Resource: demand-side resources that commit to pre-specified load reductions when system contingencies arise

Ancillary: demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance

Non-Spin Reserves: demand-side resource not connected to the system but capable of serving demand within a specified time

Spinning/Responsive Reserves: demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

Regulation: demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin

Energy-Voluntary: demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but nonperformance is not penalized

Emergency: demand-side resource curtails during system and/or local capacity constraints

Non-dispatchable[81]**:** demand-side resource curtails according to tariff structure, not instruction from a control center

Time-Sensitive Pricing: retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost and/or peak periods

Time-of-Use (TOU): rate and/or price structures with different unit prices for use during different blocks of time

Critical Peak Pricing (CPP): rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours

Real Time Pricing (RTP): rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis

System Peak Response Transmission Tariff: rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges

Capacity, Transaction and Margin Categories

Capacity Categories

Existing

a. Certain — This category includes all existing resources reasonably anticipated to be available to operate and deliver power to or into the region.
b. Uncertain — This category includes mothballed generation and portions of intermittent generation not included in the "Existing - Certain" category.

Planned — This category includes generation that has achieved one or more of these milestones:

- Construction has started
- Regulatory permits approved
  - Site permit
  - Construction permit
  - Environmental permit
- Approved by corporate or appropriate senior management
  - Included in a capital budget
  - BOD approved

[81] Projected Non-dispatchable demand response is not currently collected for reliability assessment.

Announced/Proposed — This category includes generation that is not in a prior listed category, but has been identified through one or more of the following sources:

- Corporate or appropriate senior management announcement
- Included in integrated resource plan
- Generator Interconnection Queues

Bulk Power System Transactions

Capacity Purchases and Sales – the following categories may be applied to existing and future capacity calculations. Purchases are negative values, sales are positive values. Each interregional purchase/sale has been reported.

a) Firm – contract signed
b) Non-Firm – contract signed
c) Expected – no contract executed, but in negotiation, projected, or other.
d) Provisional – transactions under study, but negotiations have not begun.

Resource Margins

Existing-Certain Capacity and Net Firm Transactions (MW) — Existing capacity resources reasonably anticipated to be available and operate as well as deliverable to or into the region plus net Firm Purchases/Sales.

Net Capacity Resources (MW) — Total Internal Capacity, less Transmission-Limited Resources, all Derates, Energy Only, and Inoperable resources; plus net Firm, Expected and Provisional Purchases/Sales. Net Capacity Resources do not include Non-Firm Purchases/Sales.

Total Potential Resources (MW) — Total Internal Capacity, less Transmission-Limited Resources, plus all Purchases/Sales.

Existing Certain Capacity and Net Firm Transactions Margin (%) — Existing-Certain Capacity and Net Firm Transactions less Net Internal Demand as a percent of Existing Certain Capacity and Net Firm Transactions.

Net Capacity Resources Margin (%) — Net Capacity Resources reduced by the Net Internal Demand as a percent of Net Capacity Resources.

Total Potential Resources Margin (%) — Total Potential Resources reduced by the Net Internal Demand as a percent of Total Potential Resources

Target Capacity Margin (%) — Established target for capacity margin by the region or sub-region.

NERC Reference Margin Level (%) — Either the Target Capacity Margin provided by the region/sub-region or NERC assigned based on capacity mix (i.e. thermal/hydro). *Each region/subregion may have their own specific margin level based on load,*

generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the regional/subregional Target Capacity Margin level is adopted as the NERC Reference Margin Level. If not, NERC assigned 13% capacity margin for predominately thermal systems and for predominately hydro systems, 9%.

How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected bulk power system in terms of two basic and functional aspects:

- Adequacy — The ability of the bulk power system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Operating Reliability — The ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements from creditable contingencies.

Regarding Adequacy, system operators can and should take "controlled" actions or procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include:

- Public appeals.
- Interruptible demand — customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator. .
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%).
- Rotating blackouts — the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders.

Under the heading of Security, are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts" — the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

What occurred in 1965 and again in 2003 in the northeast were uncontrolled cascading blackouts. What happened in the summer of 2000 in California, when supply was insufficient to meet all the demand, was a "rotating blackout" or controlled interruption of customer demand to maintain a balance with available supplies while maintaining the overall reliability of the interconnected system.