CHAPTER 3 - DESIGN FORECAST

3.1 Introduction

This Annual Plan is based on NGTL's June 2007 design forecast ("Forecast") of gas receipts and deliveries, which in turn is based on supply and market assessments completed in May 2007.

From a receipt perspective, the forecasts of field deliverability, average receipts and FS productive capability used in this Annual Plan are subject to numerous uncertainties. Producer success in developing new supply, actual levels of new firm transportation Service Agreements and changes in market demand may result in deviations from forecast values.

From a delivery forecast perspective, the forecast of maximum day delivery at the Export Delivery Points as shown in Section 3.4.2 is equal to the forecast of Firm Transportation-Delivery ("FT-D") contracts at the Export Delivery Points and does not include Short Term Firm Transportation-Delivery ("STFT") or Firm Transportation-Delivery Winter ("FT-DW") contracts. Estimates of FT-D contracts at the Export Delivery Points have become difficult to forecast given the significant gap between these contracts and the actual gas flows at the major Export Delivery Points as service with short-term contracts are increasingly being utilized.

NGTL's Forecast of gas receipt and delivery applies to the transportation design process for facilities to be in-service for the 2008/09 Gas Year. The Forecast comprises two principal parts. The first part is the gas delivery forecast (Sections 2.9.4.3 and 3.4), which is a forecast of the natural gas volumes to be delivered at all Delivery Points on the Alberta System. The second part is the receipt forecast, comprised of field deliverability, average receipts and FS productive capability forecasts (Sections 2.9.4.1, 2.9.4.2 and 3.5) for all Receipt Points on the Alberta System.

An overview of the Forecast was presented at the November 20, 2007 TTFP meeting. This chapter presents a detailed description of the Forecast.

The Forecast includes winter and summer seasonal forecasts of maximum, average, and minimum day delivery for all Delivery Points and a forecast of field deliverability, average receipts and FS productive capability for all Receipt Points on the Alberta System. Refer to Section 2.9.4 for further details on the relationship between field deliverability, average receipts, FS productive capability and Receipt Contract Demand under firm transportation Service Agreements for all Receipt Points on the Alberta System.

Gas from Storage Facilities remains a significant source of winter supply. Currently connected Storage Facilities have a maximum receipt meter capacity of 168.9 $10^6m^3/d$ (6.00 Bcf/d). Actual maximum day receipts from storage will be dependent upon market conditions, storage working gas levels, storage compression power, and Alberta System operations. A discussion of the maximum day receipt meter capability associated with Storage Facilities is provided for information purposes in Section 3.6. Refer to Section 2.6.4 for further details on the treatment of storage in the system design.

3.2 Economic Assumptions

3.2.1 General Assumptions

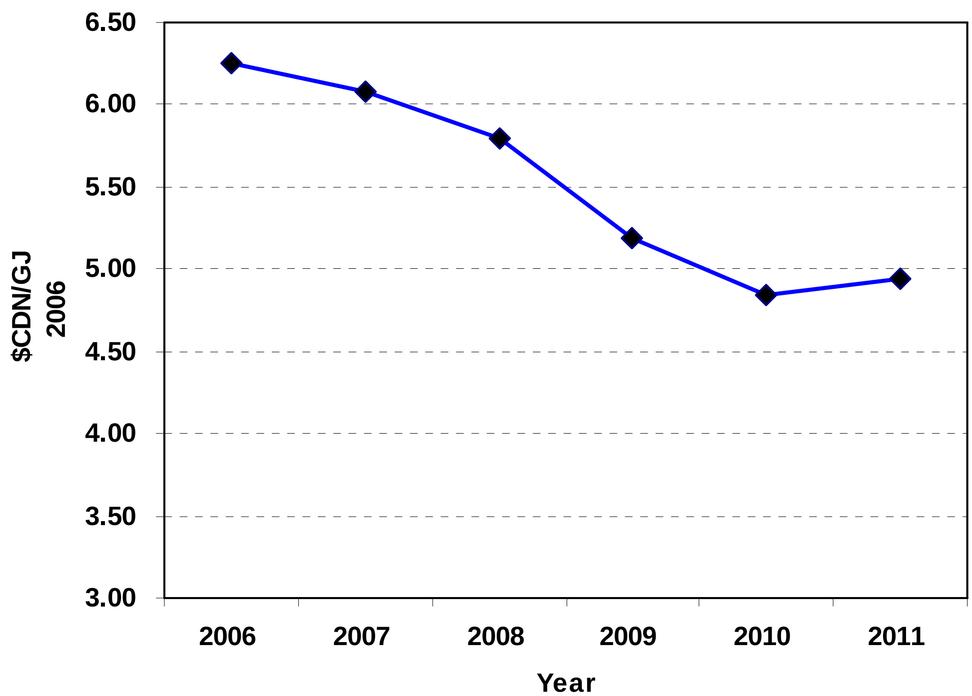
Underlying the forecast of receipts and deliveries are assumptions concerning broader trends in the North American economy and energy markets.
These assumptions, developed in January 2007, include:

- U.S. gas prices reached a peak in 2005, while average prices were lower in 2006 at $U.S. 7.23/MMBTU for NYMEX Henry Hub. Prices for 2007 are forecasted to be slightly lower at $US 7.00/MMBTU or $US 6.84/MMBTU in terms of real 2006 $US/MMBTU. Prices will slowly decline over the next several years due to slowly rising US domestic gas production and the rising influx of liquefied natural gas ("LNG"). Prices reach a low point of $U.S. 5.80/MMBTU in 2010 and then increase slowly to reach $U.S. 6.70/MMBTU by 2015. This equates to $U.S. 5.46/MMBTU in real 2006 terms;
- Gas demand is expected to increase with continued economic and population growth in both the U.S. and Canada. U.S. gas demand growth will be predominately in the electricity generation sector. Western Canadian industrial gas demand is expected to grow significantly, driven by oil sands and heavy oil activity; and
- The U.S. is expected to be able to supply most of its natural gas needs by drawing from its extensive gas resource base, with production from basins in the Rocky Mountains showing significant growth. Much of the new supply will be from unconventional gas – coal bed methane, shale gas and tight gas. U.S. gas supply has shown strength in the past few years due to strong drilling activity and is expected to grow slightly for several more years, then plateau. However, by 2015 U.S. domestic supply will start to decline slowly in aggregate and will be unable to satisfy the growth in demand. Beginning in 2008, imported LNG will play a significant role in providing additional supply to U.S. markets. This additional LNG supply will help to moderate gas prices in the North American market.

3.2.2 Gas Price

A gas price forecast is used by NGTL to determine gas demand, to evaluate the viability of gas supply development for the Forecast. The gas price forecast is based on an assessment of North American gas supply and demand. The gas price represents an Alberta average field price at a point just prior to receipt onto the Alberta System. The gas price forecast, shown in Figure 3.2.2, was developed in January 2007 and reflects the general assumptions from Section 3.2.1.

Figure 3.2.2
NGTL Gas Price Forecast
Alberta Average Field Price (Alberta Reference Price)



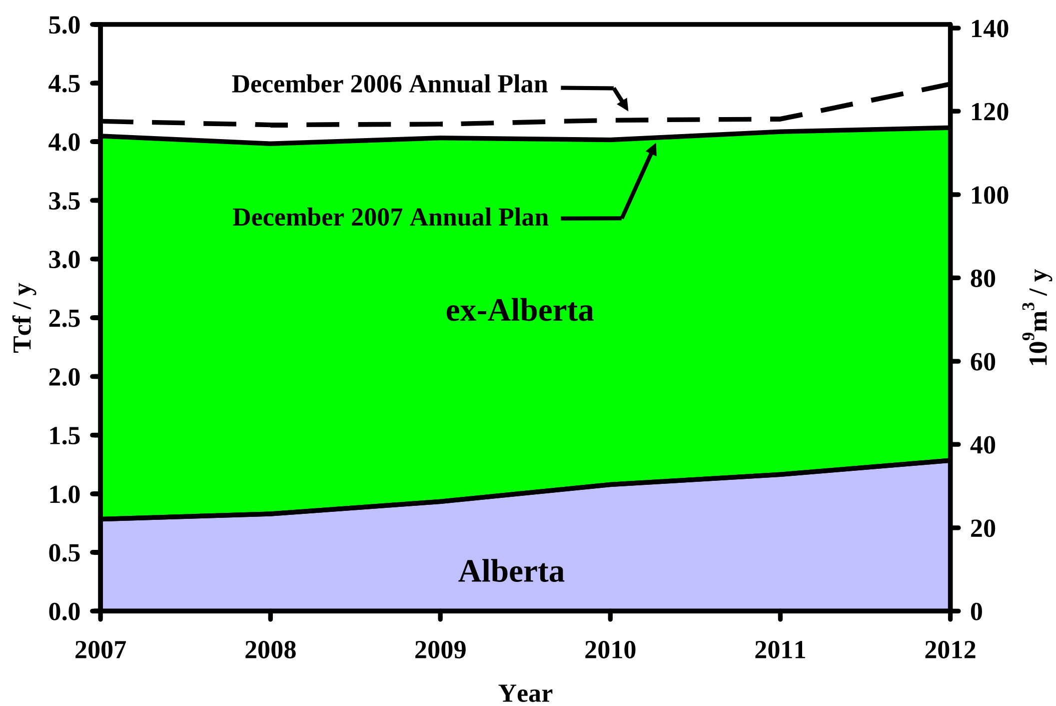
The Alberta average field price in 2007 (in real 2006 $) is forecasted at $6.07 Cdn/GJ, down from the 2006 level of $6.26 Cdn/GJ. Alberta prices decline over the next four years in line with the drop in NYMEX gas prices, but the differential narrows. By 2010, Alberta prices have declined to $4.84/GJ in real 2006 terms.

The gas price forecast affects NGTL’s receipt and delivery forecast, and is used as input into the economic analysis for new facilities. The level of the gas price affects anticipated producer activity to support continuing production from connected supplies, connection of unconnected reserves, and the activity required to discover and to develop new reserves.

3.3 System Annual Throughput

NGTL's forecast of system annual throughput is included for informational purposes. The system annual throughput forecast projects the total amount of gas to be transported by NGTL in future years and is shown in Figure 3.3.1.

Figure 3.3.1
System Annual Throughput



3.4 Gas Delivery Forecast

The gas delivery forecast describes one of the two principal components of the Forecast. The second component, the receipt forecast, is described in Section 3.5.

3.4.1 System Maximum Day Delivery Forecast

The system maximum day delivery forecast projects aggregate maximum day delivery for the entire Alberta System in each of the winter and summer seasons for the 2008/09 through 2011/12 Gas Years. NGTL does not anticipate delivering the maximum day delivery at all Delivery Points simultaneously, although the maximum day delivery at individual Delivery Points may occur at some time during a season.

A breakdown of the system maximum day delivery forecast for both the winter and summer seasons of the 2008/09 Gas Year is provided in Tables 3.4.2.1 and 3.4.2.2.

3.4.2 Export Delivery Points

The June 2007 forecast of maximum day delivery at the Export Delivery Points is consistent with NGTL's downstream capacity assumption (Section 2.6.1.3).

Table 3.4.2.1
Winter System Maximum Day Delivery Forecast

	June 2007 Design Forecast				
Gas Year	**07/08**	**08/09**	**09/10**	**10/11**	**11/12**
(Volumes in $10^6 m^3/d$ at 101.325 kPa and 15°C)					
Empress	77.4	74.4	73.4	72.6	69.0
McNeill	41.6	39.9	37.5	37.2	36.9
Alberta/B.C.	66.0	66.0	63.6	61.9	63.7
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	0.0	0.0	0.0	0.0	0.0
Cold Lake	0.0	0.0	0.0	0.0	0.0
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	2.3	2.4	2.4	2.4	2.4
Alberta	129.8	142.3	159.7	166.4	182.6
TOTAL SYSTEM	**317.1**	**324.9**	**336.5**	**340.4**	**354.6**
(Volumes in Bcf/d at 14.65 psia and 60°F)					
Empress	2.75	2.64	2.61	2.58	2.45
McNeill	1.48	1.42	1.33	1.32	1.31
Alberta/B.C.	2.35	2.34	2.26	2.20	2.26
Boundary Lake	0.00	0.00	0.00	0.00	0.00
Unity	0.00	0.00	0.00	0.00	0.00
Cold Lake	0.00	0.00	0.00	0.00	0.00
Gordondale	0.00	0.00	0.00	0.00	0.00
Alberta/Montana	0.08	0.09	0.09	0.09	0.09
Alberta	4.61	5.05	5.67	5.91	6.48
TOTAL SYSTEM	**11.26**	**11.54**	**11.95**	**12.09**	**12.59**

NOTES:
- Delivery volumes shown are not anticipated to occur simultaneously but may occur at some time during the winter season.
- Numbers may not add due to rounding.

Table 3.4.2.2
Summer System Maximum Day Delivery Forecast

	June 2007 `Design Forecast				
Gas Year	**07/08**	**08/09**	**09/10**	**10/11**	**11/12**
(Volumes in $10^6 m^3/d$ at 101.325 kPa and 15°C)					
Empress	77.0	67.8	63.4	65.5	57.7
McNeill	41.6	36.9	35.7	35.5	35.2
Alberta/B.C.	66.1	55.0	53.2	50.6	57.1
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	0.0	0.0	0.0	0.0	0.0
Cold Lake	0.0	0.0	0.0	0.0	0.0
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	2.4	2.4	2.4	2.4	2.4
Alberta	103.0	115.7	127.3	133.1	151.0
TOTAL SYSTEM	**290.2**	**277.8**	**282.1**	**287.1**	**303.4**
(Volumes in Bcf/d at 14.65 psia and 60°F)					
Empress	2.73	2.41	2.25	2.33	2.05
McNeill	1.48	1.31	1.27	1.26	1.25
Alberta/B.C.	2.35	1.95	1.89	1.80	2.03
Boundary Lake	0.00	0.00	0.00	0.00	0.00
Unity	0.00	0.00	0.00	0.00	0.00
Cold Lake	0.00	0.00	0.00	0.00	0.00
Gordondale	0.00	0.00	0.00	0.00	0.00
Alberta/Montana	0.09	0.09	0.09	0.09	0.09
Alberta	3.65	4.11	4.52	4.73	5.36
TOTAL SYSTEM	**10.30**	**9.86**	**10.02**	**10.20**	**10.77**

NOTES:
- Delivery volumes shown are not anticipated to occur simultaneously but may occur at some time during the summer season.
- Numbers may not add due to rounding.

3.4.2.1 Empress

The forecast of maximum day delivery at the Empress Export Delivery Point reflects the forecast level of firm transportation Service Agreements at the Empress Export Delivery Point.

The June 2007 forecast winter maximum day delivery for the 2008/09 Gas Year at the Empress Export Delivery Point is 74.4 $10^6m^3/d$ (2.64 Bcf/d). This represents a decrease of 3.0 $10^6m^3/d$ (0.11 Bcf/d), or 3.9 percent, from the winter season maximum day delivery in the June 2007 forecast for the 2007/08 Gas Year.

The June 2007 forecast summer maximum day delivery for the 2008/09 Gas Year at the Empress Export Delivery Point is 67.8 $10^6m^3/d$ (2.41 Bcf/d). This represents a decrease of 9.3 $10^6m^3/d$ (0.33 Bcf/d), or 12.0 percent, from the summer season maximum day delivery in the June 2007 forecast for the 2007/08 Gas Year.

3.4.2.2 McNeill

The forecast of maximum day delivery at the McNeill Export Delivery Point for 2008/09 reflects the forecast level of firm transportation Service Agreements at the McNeill Export Delivery Point.

The June 2007 forecast winter maximum day delivery for the 2008/09 Gas Year at the McNeill Export Delivery Point is 39.9 $10^6m^3/d$ (1.42 Bcf/d). This represents a decrease of 1.7 $10^6m^3/d$ (0.06 Bcf/d), or 4.2 percent, from the winter season maximum day delivery in the June 2007 forecast for the 2007/08 Gas Year.

The June 2007 forecast summer maximum day delivery for the 2008/09 Gas Year at the McNeill Export Delivery Point is 36.9 $10^6m^3/d$ (1.31 Bcf/d). This represents a decrease of 4.7 $10^6m^3/d$ (0.17 Bcf/d), or 11.3 percent, from the summer season maximum day delivery in the June 2007 forecast for the 2007/08 Gas Year.

3.4.2.3 Alberta/British Columbia

The forecast of maximum day delivery at the Alberta/British Columbia Export Delivery Point reflects the forecast level of firm transportation Service Agreements at the Alberta/British Columbia Export Delivery Point.

The June 2007 forecast winter maximum day delivery for the 2008/09 Gas Year at the Alberta/British Columbia Export Delivery Point is 66.0 $10^6m^3/d$ (2.34 Bcf/d). This represents a decrease of 0.02 $10^6m^3/d$ (0.01 Bcf/d), or 0.2 percent, from the winter season maximum day delivery in the June 2007 forecast when compared to the 2007/08 Gas Year.

The June 2007 forecast summer maximum day delivery for the 2008/09 Gas Year at the Alberta/British Columbia Export Delivery Point is 55.0 $10^6m^3/d$ (1.95 Bcf/d). This represents a decrease of 11.2 $10^6m^3/d$ (0.40 Bcf/d), or 16.9 percent, from the summer season maximum day delivery in the June 2007 forecast for the 2007/08 Gas Year.

3.4.2.4 Other Exports

Boundary Lake, Unity, Cold Lake, Gordondale and Alberta/Montana.

The June 2007 forecast maximum day delivery for the 2008/09 Gas Year for the Alberta/Montana Export Delivery Point is 2.4 $10^6m^3/d$ (0.09 Bcf/d).

The June 2007 forecast maximum day delivery for the 2008/09 Gas Year for each of the Boundary Lake, Unity, Cold Lake and Gordondale Delivery Points is zero. This is unchanged from the maximum day delivery forecast for the 2007/08 Gas Year.

3.4.3 Alberta Deliveries

The June 2007 Alberta maximum day delivery forecast for the winter season of the 2008/09 Gas Year is 142.3 $10^6m^3/d$ (5.05 Bcf/d). This is an increase of 12.4 $10^6m^3/d$ (0.44 Bcf/d), or 9.6 percent, from the 2007/08 Gas Year winter season value in the June 2007 forecast. The June 2007 Alberta maximum day delivery forecast for the summer season of the 2008/09 Gas Year is 115.7 $10^6m^3/d$ (4.11 Bcf/d). This is an increase of 12.7 $10^6m^3/d$ (0.45 Bcf/d), or 12.4 percent, from the 2007/08 Gas Year summer season value in the June 2007 forecast.

NGTL considered several sources of information in developing its Alberta maximum day delivery forecast. First, operators of downstream facilities such as connecting pipelines and industrial plant operators were requested to provide a forecast of their maximum, average, and minimum requirements for deliveries from the Alberta System over the next ten years. NGTL analyzed the forecasts and compared them to historical flow patterns at the Alberta Delivery Points. In cases where NGTL's analysis differed substantially with the operator's forecast, NGTL contacted the operator and either the operator's forecast was revised or NGTL adjusted its analysis. In cases where the operator did not provide a forecast, NGTL based its forecast on historical flows and growth rates for specific demand sectors.

A summary of winter and summer maximum day delivery for Alberta Deliveries from the Forecast by NGTL project area is shown in Tables 3.4.3.1, and 3.4.3.2, respectively.

Table 3.4.3.1
Winter Maximum Day Delivery Forecast

Project Area	June 2007 Design Forecast ($10^6 m^3/d$)	
	2007/08	**2008/09**
Peace River	6.0	6.7
North and East	63.6	74.7
Mainline	55.4	55.9
Gas taps	4.9	4.9
TOTAL ALBERTA	**129.8**	**142.3**
Project Area	**June 2007 Design Forecast (Bcf/d)**	
	2007/08	**2008/09**
Peace River	0.21	0.24
North and East	2.26	2.65
Mainline	1.97	1.98
Gas taps	0.17	0.18
TOTAL ALBERTA	**4.61**	**5.05**

NOTES:
- Numbers may not add due to rounding.
- Gas taps are located in all areas of the province.

Table 3.4.3.2
Summer Maximum Day Delivery Forecast

Project Area	June 2007 Design Forecast ($10^6 m^3/d$)	
	2007/08	**2008/09**
Peace River	4.7	4.6
North and East	62.8	74.8
Mainline	33.3	34.0
Gas taps	2.3	2.3
TOTAL ALBERTA	**103.0**	**115.7**
Project Area	**June 2007 Design Forecast (Bcf/d)**	
	2007/08	**2008/09**
Peace River	0.17	0.16
North and East	2.23	2.66
Mainline	1.18	1.21
Gas taps	0.08	0.08
TOTAL ALBERTA	**3.65**	**4.11**

NOTES:
- Numbers may not add due to rounding.
- Gas taps are located in all areas of the province.

3.5 Receipt Forecast

The following receipt forecasts comprise the second principal part of the Forecast.

3.5.1 System FS Productive Capability Forecast

The system FS productive capability forecast from the Forecast is 277.5 $10^6m^3/d$ (9.85 Bcf/d) in the 2008/09 Gas Year. This is up slightly from the 2007/08 Gas Year forecast of 276.7 $10^6m^3/d$ (9.82 Bcf/d) in the June 2007 forecast.

A summary of system FS productive capability from the Forecast by NGTL project area is shown in Table 3.5.1.

Table 3.5.1
System FS Productive Capability Forecast

Project Area	June 2007 Design Forecast ($10^6m^3/d$)				
	2007/08	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Peace River	107.6	110.6	111.4	111.5	105.8
North and East	35.8	33.7	34.7	36.9	36.9
Mainline	133.3	133.2	134.2	132.4	132.4
TOTAL SYSTEM	**276.7**	**277.5**	**280.2**	**280.8**	**275.1**
Project Area	**June 2007 Design Forecast (Bcf/d)**				
	2007/08	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Peace River	3.82	3.93	3.95	3.96	3.75
North and East	1.27	1.19	1.23	1.31	1.31
Mainline	4.73	4.73	4.76	4.70	4.70
TOTAL SYSTEM	**9.82**	**9.85**	**9.95**	**9.97**	**9.76**

NOTE:
- Numbers may not add due to rounding.

3.5.2 System Field Deliverability Forecast

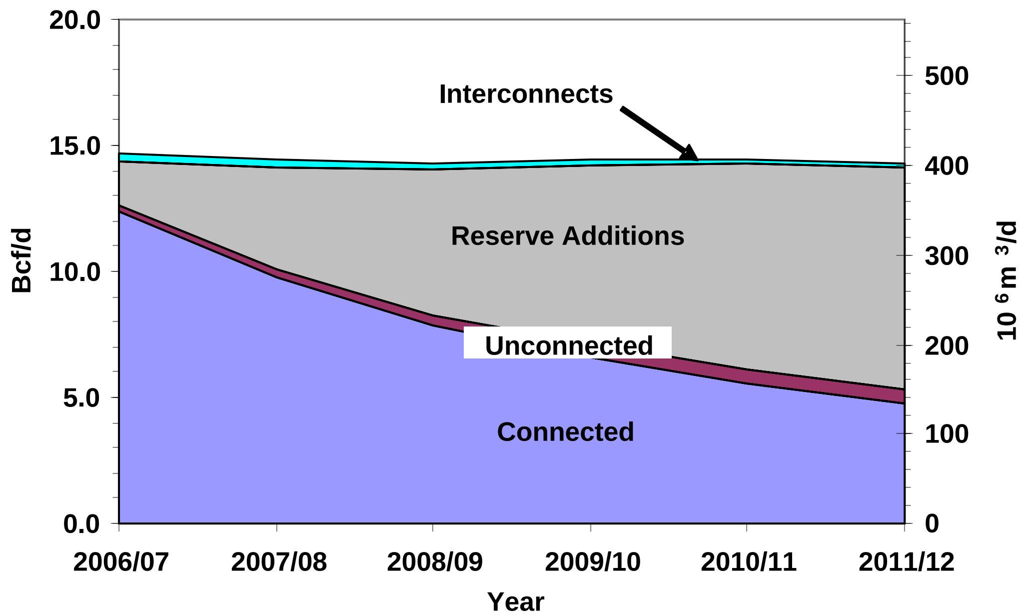
In updating the field deliverability for the Forecast, three major sources of gas supply were included:

- Connected and Unconnected Reserves – supply from established reserves upstream of NGTL's Receipt Points;
- Reserve Additions - supply from undiscovered reserves, including unconventional coalbed methane and tight gas; and
- Interconnections - supply from interconnections with other pipeline systems.

Incremental supply from reserve additions and from the unconnected component of discovered reserves are expected to become available to offset declines in field deliverability from connected established reserves as economics permit.

Figure 3.5.2 shows the system field deliverability and its composition by supply source. In aggregate, NGTL expects the WCSB field deliverability to remain relatively flat over the forecast period based on the Forecast.

Figure 3.5.2
System Field Deliverability by Component



Gas supplied from Storage Facilities has not been included in the data presented in this section. Information pertaining to gas supply from Storage is contained in Section 3.6.

Supply from reserve additions was forecast on an area basis, based on economic potential estimates from the Canadian Gas Potential Committee Report – Natural Gas Potential in Canada – 2005, and from expected delivery requirements. The supply from reserve additions was then allocated to each Receipt Point within the forecast area. The allocated supply from reserve additions was combined with the established supply forecast from connected gas and existing economic unconnected gas to provide a forecast of future supply at each Receipt Point.

A summary of system field deliverability from the June 2007 forecast by NGTL project area is shown in Table 3.5.2.

Table 3.5.2
System Field Deliverability Forecast

Project Area	June 2007 Design Forecast ($10^6m^3/d$)				
	2007/08	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Peace River	150.2	150.8	152.5	153.8	147.5
North and East	60.4	56.7	58.2	61.4	62.2
Mainline	195.6	194.5	195.8	192.7	192.4
TOTAL SYSTEM	**406.2**	**402.0**	**406.6**	**408.0**	**402.1**
Project Area	**June 2007 Design Forecast (Bcf/d)**				
	2007/08	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Peace River	5.3	5.4	5.4	5.5	5.2
North and East	2.1	2.0	2.1	2.2	2.2
Mainline	6.9	6.9	6.9	6.8	6.8
TOTAL SYSTEM	**14.4**	**14.3**	**14.4**	**14.5**	**14.3**

NOTES:
- Numbers may not add due to rounding.
- Includes unconventional gas.

3.5.3 Firm Transportation Service Agreements

The following is a summary of the aggregate Receipt Contract Demand forecast to be held under firm transportation Service Agreements on the Alberta System.

The June 2007 forecast of aggregate Receipt Contract Demand under firm transportation Service Agreements is 279.6 $10^6m^3/d$ (9.92 Bcf/d) for the 2008/09 Gas Year, as shown in Table 3.5.3. This is an increase of 2.0 $10^6m^3/d$ (0.07 Bcf/d), or 0.7 percent, from the 2007/08 Gas Year and reflects the net effect of both new and non-renewing firm transportation Service Agreements.

Table 3.5.3
Forecast of Receipt Contract Demand under Firm Transportation Service Agreements

Gas Year	June 2007 Design Forecast	
	(10^6m^3/d)	(Bcf/d)
2007/08	277.6	9.85
2008/09	279.6	9.92
2009/10	284.6	10.10
2010/11	288.2	10.23
2011/12	283.8	10.07

NOTE:
- Represents Alberta System peak values anticipated in Gas Year.

3.5.4 System Average Receipts

The system average receipt forecast from the Forecast is 312.0 10^6m^3/d (11.08 Bcf/d) in the 2008/09 Gas Year. This is up slightly from the 2007/08 Gas Year forecast of 311.1 10^6m^3/d (11.04 Bcf/d) in the June 2007 forecast.

A summary of system average receipts from the Forecast by NGTL project area is shown in Table 3.5.4.

Table 3.5.4
System Average Receipts

	June 2007 Design Forecast ($10^6m^3/d$)				
Project Area	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Peace River	116.3	118.2	117.5	119.6	118.4
North and East	43.7	42.0	42.3	45.9	48.5
Mainline	151.1	151.8	149.8	149.2	153.0
TOTAL SYSTEM	**311.1**	**312.0**	**309.6**	**314.7**	**319.8**
	June 2007 Design Forecast (Bcf/d)				
Project Area	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Peace River	4.13	4.20	4.17	4.25	4.20
North and East	1.55	1.49	1.50	1.63	1.72
Mainline	5.36	5.39	5.32	5.30	5.43
TOTAL SYSTEM	**11.04**	**11.08**	**10.99**	**11.17**	**11.35**

3.5.5 Established Natural Gas Reserves

Table 3.5.5.1 presents a summary of remaining established gas reserves in Alberta by NGTL project area as of October 2006. This summary is based on NGTL's assessment of available information. The Board estimates 1106.9 10^9m^3 (39.3 Tcf) of CBM and conventional gas reserves to year end 2005. NGTL's estimate is based on the Board's established reserves which existed at year end 2005 augmented by more recent data provided by NGTL customers and by additional reserves discovered as of October 2006. The reserves have been adjusted for production to October 2006.

NGTL's estimate of 1113.4 10^9m^3 (39.5 Tcf) remaining established gas reserves in Alberta is a decrease of about 14.6 10^9m^3 (0.5 Tcf), or 1.3 percent, from the 1128.0 10^9m^3 (40.0 Tcf) reported in the December 2006 Annual Plan.

Table 3.5.5.1
Remaining Established Alberta Gas Reserves by Project Area

Project Area	NGTL Estimate (10^9m^3)	NGTL Estimate (Tcf)
Peace River	212	7.5
North & East	195	6.9
Mainline	466	16.6
Other[1]	239	8.5
Total[2]	**1113**	**39.5**

NOTES:
1 Reserves not directed to NGTL.
2 Numbers may not add due to rounding.

Table 3.5.5.2 presents the estimate of remaining established reserves. For British Columbia and the lower Northwest Territories, the estimate is limited to areas connected or likely to be connected to the Alberta System.

Table 3.5.5.2
Remaining Established Reserves

Reserve Basis	Alberta		B.C. and N.W.T.		Total	
	10^9m^3	Tcf	10^9m^3	Tcf	10^9m^3	Tcf
Remaining Established Reserves connected to NGTL [1,2]	874	31.0	97	3.4	971	34.5
Remaining Established Reserves not connected to NGTL [3,4]	239	8.5	-	-	239	8.5
TOTAL	**1113**	**39.5**	**97**	**3.4**	**1211**	**43.0**

NOTES:
1 The remaining established reserves are those connected and those expected to be connected to the Alberta System and include reserve estimates from NGTL initiated reserve studies.
2 Reserves not connected to the Alberta System are those which would be transported on other systems.
3 NGTL is not providing estimates of B.C. reserves that are not forecasted to flow on its pipeline system.
4 Numbers may not add due to rounding.

3.6 Storage Facilities

There are seven storage facilities presently connected to the Alberta System, as shown in Table 3.6.1. They are located at the AECO ‘C’, Big Eddy, Carbon, Chancellor, Crossfield East #2, January Creek and Severn Creek Meter Stations (Figure 2.6.1.4). The total deliverability from Storage Facilities is significant when compared to the field deliverability available from other Receipt Points on the Alberta System.

The receipt meter capacity for each of the connected Storage Facilities for the 2008/09 Gas Year is shown in Table 3.6.1.

Table 3.6.1
Receipt Capacity from Storage Facilities

	Receipt Meter Capacity from Storage Facilities 2008/09	
	$10^6m^3/d$	Bcf/d
AECO C	50.7	1.80
Big Eddy	35.4	1.25
Carbon	13.8	0.49
Chancellor	35.2	1.25
Crossfield East #2	14.1	0.50
January Creek	14.1	0.50
Severn Creek	5.6	0.21
TOTAL	**168.9**	**6.00**

NOTES:
- Storage is presently considered as an interruptible supply source. Refer to Section 2.6.4 for details on the treatment of storage in the system design.
- Numbers may not add due to rounding.

3.7 Receipt to Delivery Comparisons

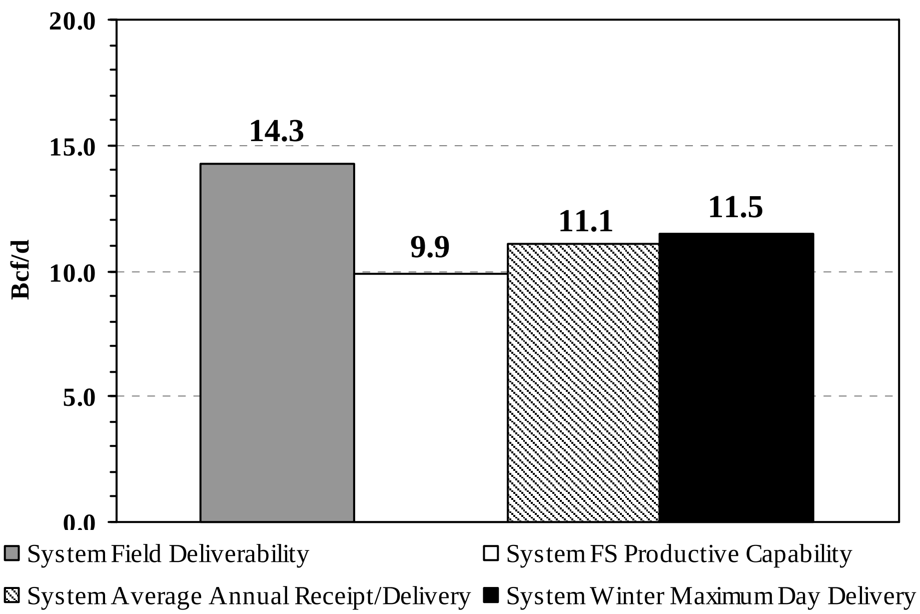
This section discusses the relative levels of gas receipt and delivery forecasts for the Alberta System, as were described in Sections 3.4 and 3.5, based on the Forecast.

For illustrative purposes, Figure 3.7.1 also shows the forecast of the system FS productive capability, system field deliverability, the system average annual delivery and the system winter maximum day delivery for the 2008/09 Gas Year.

It should be noted that Storage Facilities are anticipated to contribute significant additional receipts to the pipeline system during peak demand conditions. As described in Section 2.6.1.4, gas deliverability from Storage Facilities is provided as an interruptible service on the Alberta System. The capability of the system to receive large withdrawals from Storage Facilities will be dependent upon the prevailing operating conditions and corresponding ability to move interruptible volumes at the time the withdrawals are requested. For this reason, the potential receipt contribution from Storage Facilities is not shown in Figure 3.7.1.

System field deliverability is projected to be 402.0 $10^6 m^3/d$ (14.3 Bcf/d) as shown in Figure 3.7.1. Based on the aggregate of each Receipt Point's FS productive capability forecast, the system FS productive capability is 277.5 $10^6 m^3/d$ (9.9 Bcf/d). Average annual receipt volumes are equal to the average annual delivery volumes and are projected to be 312.0 $10^6 m^3/d$ (11.1 Bcf/d). The winter maximum day delivery volume is projected to be 324.9 $10^6 m^3/d$ (11.5 Bcf/d).

Figure 3.7.1
Receipt/Delivery Comparison
2008/09 Gas Year



NOTE:
- Storage excluded.