Appendix to Direct Testimony of Richard J. Zuraski

Assumed Values of Inputs Used in Analysis

Inputs Held Constant

1. Energy Production from New Generating Resources[i]
   14,961,568 MWH per year

2. General Price Inflation Rate[ii]
   2.5% per year

3. Debt Term[iii]
   20 years

4. Depreciation for Tax Purposes[iv]
   RICL project: MACRS 15-year 150% declining balance method
   Wind projects: MACRS 5-year 200% declining balance method

5. RICL Project Useful Life[v]
   40 years

6. RICL Project O&M Costs[vi]
   1% of Capital Costs in 2017, increasing with general price inflation rate of 2.5%

7. RICL Property Taxes[vii]
   Values shown in RICL Exhibit 10.8

8. RICL Project State Income Tax Rate[viii]
   12%

9. Federal Income Tax Rate for all projects[ix]
   35%

10. Iowa Wind Farm Property Taxes[x]
    Valuation: Based on original cost with an exemption that varies from 100% in year 1 to 70% by last year of asset's assumed life. Tax Rate: 3.5%.

11. Iowa Wind Farm State Income Tax[xi]
    12%

12. Iowa Wind Farm Energy Value Factor[xii]
    98% of around-the-clock average LMP prices

13. Iowa Wind Farm Capacity Resource Credit[xiii]
    13.3%

14. Illinois Wind Farm Property Taxes[xiv]
    Valuation: $120,000 per MW (2007) times a CPI Trending Factor, which was 1.12 in 2012. Tax Rate: 7%.

15. Illinois Wind Farm State Income Taxes[xv]
    9.5%

16. Illinois Wind Farm Energy Value Factor[xvi]
    95% of around-the-clock average LMP prices

17. Illinois Wind Farm Capacity Resource Credit[xvii]
    13.0%

18. Illinois Combined Cycle Power Plant Property Taxes[xviii]
    Valuation: Original value divided by 3 in year 1, depreciated by original value divided by 25 over 25 years. Tax Rate: 0.7%

19. Illinois Combined Cycle Power Plant State Income Tax Rate
    Same as for Illinois Wind Farms

20. Illinois Combined Cycle Power Plant Capacity Factor
    60%

21. Illinois Combined Cycle Power Plant State Ancillary Service Revenues
    $3,198 per MW-year

Variables

1A. Minimum Debt Coverage Ratios (Model A[xix])

Case 0 (Optimistic)	1.25
Case 1 (Base)	1.50
Case 2 (Pessimistic)	1.75

1B. Equity as a Percent of Total Capital (Model B[xx])

Case 0 (Optimistic)	20%
Case 1 (Base)	35%
Case 2 (Pessimistic)	50%

2. Equity Capital Real Rate of Return[xxi]

Case 0 (Optimistic)	5.0%
Case 1 (Base)	7.5%
Case 2 (Pessimistic)	10.0%

3. Debt Capital Real Interest Rate[xxii]

Case 0 (Optimistic)	0.97%
Case 1 (Base)	2.90%
Case 2 (Pessimistic)	3.87%

4. RICL Project Capital Cost[xxiii]

Case 0 (Optimistic)	$1.6 billion
Case 1 (Base)	$2.0 billion
Case 2 (Pessimistic)	$2.4 billion

5. Electricity Commodity Price Nominal Inflation Rates[xxiv]

Case 0 (Optimistic)	2.2%
Case 1 (Base)	3.2%
Case 2 (Pessimistic)	4.2%

6. Power Plant Useful Life[xxv]

Case 0 (Pessimistic)	21 years
Case 1 (Base)	25 years
Case 2 (Optimistic)	29 years

7. Wind Farm Cost and Cost Inflation Rates[xxvi]

	Cap Cost (2011$ per MW)	Fixed O&M Cost (2011$ per MW-yr)	Cap Cost Nom. Inflation (% per year)	Fixed O&M Cost Nom. Inflation (% per year)
Case 0	$2,175,000	$38,860	0.40%	0.40%
Case 1	$2,175,000	$38,860	1.00%	1.00%
Case 2	$2,175,000	$38,860	2.50%	2.50%

8. Impact on Capacity Factor & Avg LMPs of Wind Farms in Iowa w/out RICL Project[xxvii]

	CF	LMPs
Case 0 (Pessimistic)	0%	1
Case 1 (Base)	3%	1
Case 2 (Optimistic)	6%	1

9. Illinois Wind Farm Capacity Factors[xxviii]

Case 0 (Pessimistic)	25.44%
Case 1 (Base)	31.65%
Case 2 (Optimistic)	37.86%

10. Natural Gas Prices[xxix]

Case 0 (Optimistic)	Rate of increase decreased by half, relative to Base Case
Case 1 (Base)	EIA 2013 Early Release AEO Reference Case times 0.96

Case 2 (Optimistic) Rate of increase increased by half, relative to Base Case

11. Combined Cycle Power Plant Costs and Heat Rate[xxx]

	Cap Cost (2011$ per MW)	Fixed O&M Cost (2011$ per MW-yr)	Variable O&M ($ per MWH)	Heat Rate (MMBtu/MWH)
Case 0	$995,940	$14,949	$3.18	6.270
Case 1	$1,006,000	$15,100	$3.21	6.333
Case 2	$1,036,000	$15,090	$3.21	6.430

[i] See testimony.

[ii] Inflation rate of 2.5% is assumed in the analysis of at least some of the RICL witnesses in this proceeding (for example, see RICL Ex. 4.0, p. 23, footnote 17). It is used in this analysis for comparability. In addition, see the inflation forecast information in end note xxii, below.

[iii] Debt term assumed to be 20 years for all projects. For RICL project, this assumption is consistent with RICL Exhibit 10.8. For wind farm projects, this is consistent with the minimum useful life assumption of 21 years.

[iv] For RICL Project, tax depreciation assumption based on RICL response to Staff Data Request RJZ 1.17(k). For both the RICL and the wind projects, the tax depreciation assumptions are consistent with the Internal Revenue Service's "2012 Instructions for Form 4562 Depreciation and Amortization" (Jan 16, 2013, Cat. No. 12907Y) and its Publication 946 "How To Depreciate Property" (Feb 15, 2013, Cat. No. 13081F), both available from http://www.irs.gov/uac/Form-4562,-Depreciation-and-Amortization (Website last visited on 5/2/2013).

[v] RICL useful life assumed to be 40 years, based on RICL Exhibit 10.8 (which uses a 40 year time horizon for the project). In addition, KEMA, Inc. ("LIFE-CYCLE 2012: Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Final Report," November 15, 2012, pp. 1-1 and 9-1) support using a 40-year assumption for a study of transmission system life-cycle costs. The MISO 2012 Transmission Expansion Plan (2013-01-30) uses both 20-year and 40-year time horizons for its analysis of transmission expansion benefits. In MISO's "Multi Value Project Portfolio: Detailed Business Case," (Available from https://www.midwestiso.org/_layouts/miso/ecm/redirect.aspx?id=126541), Slide 24 indicates:

- Overhead transmission lines are projected to have a total lifespan of 70 – 80 years
- The tariff typically refers to a 20 year time horizon for B/C calculations
- A 40 year time span allows additional benefits to be captured for each transmission facility, without requiring extremely long range projections
- It also matches the assumed book life of the facilities

[vi] The RICL O&M cost assumptions are based on RICL Exhibit 10.8 and RICL's response to Staff Data Request RJZ 1.17(e) and (f), where RICL witness Barry states, "These reflect typical industry maintenance costs for HVDC lines and are consistent with the experience of Clean Line's technical team."

[vii] The property tax values assumed in the analysis were taken directly from RICL Ex. 10.8.

[viii] Marginal income tax rate of 12% based on review of the following Iowa government web site: http://www.iowa.gov/tax/taxlaw/taxtypes.html#corp

[ix] Marginal Federal Income tax rate of 35% based on tax schedule found in IRS Publication 542 "Corporations" (Rev. March 2012, Cat. No. 150720), which is available from http://www.irs.gov/Forms-&-Pubs . In addition, for RICL, RICL's response to Staff data request RJZ 1.17(l) states: "Rock Island currently assumes its owners pay income tax at the maximum applicable federal rate (currently 35%)."

[x] Iowa wind farm property taxes based on review of information found at the following Iowa government web sites: http://www.iowa.gov/tax/locgov/iowa-property-tax.html , http://www.dom.state.ia.us/local/county/county_prop_tax.html, and http://www.dom.state.ia.us/local/valuations/index.html Using the most recent three to twelve years of data, the average ratio of [property taxes assessed to industrial property] divided by [the valuation of industrial property] is 3.5%.

[xi] Marginal income tax rate of 12% based on review of the following Iowa government web site: http://www.iowa.gov/tax/taxlaw/taxtypes.html#corp

[xii] Energy value factor assumed to be 0.98 based on Commission approved 2010 long term wind contracts with ComEd and Ameren, and on review of MISO LMP data (Illinois Hub Day-ahead) combined with wind output data, where, on average, over the course of a year, the value of wind output is approximately 0.98 of the average around-the-clock LMP.

[xiii] MISO Capacity Resource Factor based on the MISO report, "Planning Year 2013-2014 Wind Capacity Credit," December 2012, available from https://www.midwestiso.org/_layouts/miso/ecm/redirect.aspx?id=141841.

[xiv] Illinois wind farm property tax assumptions based on review of information on the following Illinois government web sites: http://tax.illinois.gov/Publications/Sales/SalesTaxRates/PropertyTax.htm, http://tax.illinois.gov/LocalGovernment/PropertyTax/, http://tax.illinois.gov/LocalGovernment/PropertyTax/WindDevices.htm , and http://tax.illinois.gov/AboutIdor/TaxStats/PropertyTaxStats/2011/index.htm. The assumed tax rate of 7% is based on 2011 Property Tax Statistics: Table 8 taxes from industrial property class (excluding Cook County and the collar counties). Since Illinois property tax valuations are one-third of the fair market value, a rate of 7% per dollar of assessed value is equivalent to a rate of $2\,^{1}/_{3}$% per dollar of market value.

[xv] Illinois marginal tax rate of 9.5% based on review of Illinois tax database, available from http://www.revenue.state.il.us/Publications/Sales/SalesTaxRates/FixedRatesIncome.htm. The 9.5% rate is the sum of the Business Income Tax (7%) and the Personal Property Replacement Tax (2.5%).

[xvi] Energy value factor assumed to be 0.98 based on Commission approved 2010 long term wind contracts with ComEd and Ameren, and on review of PJM LMP data (NIHUB Day-ahead) combined with wind output data, where, on average, over the course of a year, the value of wind output is approximately 0.98 of the average around-the-clock LMP.

[xvii] The 13% PJM capacity resource factor based on PJM Manual 21, Revision 09, Effective Date May 1, 2010, p. 19: "H. Currently effective class average capacity factors are 13% for wind and 38% for solar units." The manual is available from http://www.pjm.com/documents/manuals.aspx. The 13% factor is also consistent with the "2015/2016 RPM Base Residual Auction Results," p. 13, which states: "The capacity factor applied to wind resources is 13%, meaning that for every 100 MW of wind energy, 13 MW are eligible to meet capacity requirements." That report is available from http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item09.

[xviii] See note xiv.

[xix] Minimum debt service coverage ratio not used in Model B. In Model A, the cases are 1.25, 1.5, and 1.75 (i.e., 1.5 plus and minus 0.25). The optimistic case assumption of 1.25 was also used in RICL Exhibit 10.8 and referred to in the testimony of RICL witness Berry (RICL Exhibit 10.0, p. 38). The three cases used for this analysis were based on judgment after review of the following information.

According to an article posted on the NREL website, "For renewable projects, DSCRs have been between 1.2 and 1.5 (i.e., $120–$150 for every $100 in obligations). But today, higher DSCRs are required as debt markets are tight." ("Staying (Cash Flow) Positive: Investor Requirements for RE Project Financing," submitted by Karlynn Cory on Mon, 11/08/2010 - 8:00am, https://financere.nrel.gov/finance/content/staying-cash-flow-positive-investor-requirements-re-project-financing).

In an article published on the Federal Reserve Board's web site, concerning commercial mortgage backed securities, among a sample of 31657 loans, the average debt service coverage ratio was 1.47, with a standard deviation of 0.40 (Lamont K. Black, Chenghuan Sean Chu, Andrew Cohen, and Joseph B. Nichols, "Differences Across Originators in CMBS Loan Underwriting," Divisions of Research & Statistics and Monetary Affairs, Federal Reserve Board, Washington, D.C., Finance and Economics Discussion Series: 2011-05, p. 26; available from http://www.federalreserve.gov/pubs/feds/2011/201105/#footnote_reference_5).

In an LBNL report, the authors state: "While conversations with developers suggest that required minimum debt service coverage ratios (DSCR) may range from as low as 1.25 for wind to as high as 2.0 for some geothermal projects, we hold both wind and geothermal to the same standard – a minimum DSCR of 1.5 – for the sake of simplicity." (Mark Bolinger, Ryan Wiser, and Bill Golove, 'Revisiting the "Buy versus Build" Decision for Publicly Owned Utilities in California Considering Wind and Geothermal Resources,' Lawrence Berkeley National Laboratory, LBNL-48831, October 2001, p. 9, fn. 18; available from http://emp.lbl.gov/reports.).

In an earlier LBNL report, the authors stated, "DSCR requirements have changed with time, and vary substantially by project. A range of 1.3-2.0 is typical for privately owned, project-financed windpower projects … indicates that first-year DSCRs of 1.35-1.40 are currently common, often rising with time if revenue streams are uncertain." (Ryan Wiser and Edward Kahn, "Alternative Windpower Ownership Structures: Financing Terms and Project Costs," Lawrence Berkeley National Laboratory, Energy & Environment Division, LBNL-38921, May 1996, p. 11; available from http://emp.lbl.gov/reports.).

Moody's Investor Service Rating Methodology for Power Generation Projects (December 21, 2012), shows the following rating grid mapping for fully amortizing financing structures (p. 22):

Aa	**A**	**Baa**	**Ba**	**B**	**Caa**
Average DSCR greater than 3.50x	Average DSCR of 1.90x to 3.50x	Average DSCR of 1.40x to 1.90x.	Average DSCR of 1.20x to 1.40x.	Average DSCR of 1.10x to 1.20x	Average DSCR of 1.00x to 1.10x

The same Moody's report also states:

> We will also look at the variability year to year in the DSCR to see how stable it is and to see how much lower the minimum DSCR is than the average. Historically, Moody's has not looked favorably upon amortizing structures that have low debt amortization in the early years and high debt amortization in the later years, resulting in a vastly different DSCR over the life of the deal. Therefore, Moody's will also consider the minimum DSCR in the structure. In general, at the lower 1.40x end of the range for Baa, there would be little tolerance for a minimum DSCR being below the average.
>
> (Moody's Investor Service Rating Methodology for Power Generation Projects (December 21, 2012), p. 22).

[xx] Equity levels solved for in Model A. In Model B, the equity level cases of 20%, 35%, and 50% are based on the following considerations. First, under Model A, the base case solution for equity capital ranges between 30% and 31%. Second, under Model A, the solved-for equity levels range from 13% to 53%. Third, the 2010 Wind Technologies Report, available from http://nrelpubs.nrel.gov/ , reports that in 2010, $8.4 billion in debt capital (p. 32) and $4 billion in tax equity (p. 31) was raised to finance wind farms, implying an equity level of 32%. However, the 2011 Wind Technologies Report, available from http://nrelpubs.nrel.gov/ , reports that in 2011, $5.9 billion in debt capital (p. 26) and $6 billion in tax equity (p. 27) was raised to finance wind farms, implying an equity level of 50%. Moody's Investor Service Rating Methodology for Power Generation Projects (December 21, 2012), shows the following rating grid mapping for the rating category of Total Adjusted Debt divided by Total Capitalization (p. 24), which would place the low case in my analysis at the extreme of the B rating range, and the high case at the extreme of the Ba range.

Aa	**A**	**Baa**	**Ba**	**B**	**Caa**
<20%	20% - 35%	36% - 50%	51% - 60%	61%-80%	more than 80%

[xxi] Base case real equity rate of return was set equal to the 10% nominal rate of return recently approved by the Commission for the FutureGen 2.0 (see Order, ICC Docket 12-0544) less the 2.5% rate of general inflation assumed in the analysis of at least some of the RICL witnesses in this proceeding (for example, see RICL Ex. 4.0, p. 23, footnote 17), as well as in Staff's sensitivity analysis. The pessimistic case is 2.5% higher and the optimistic case is 2.5% lower than the base case.

[xxii] Base case real interest rate was set equal to the approximate average Moody's Baa bond rate, as reported by the Federal Reserve (http://www.federalreserve.gov/releases/h15/data.htm) during the time period that the sensitivity analysis initially was developed (late January) (4.8%) less observed general price inflation from December 2011 through December 2012, as reported by the Bureau of Labor Statistics (specifically, the percentage change in the CPI-U, all items less energy, available from http://www.bls.gov/cpi/#tables) (1.9%). (Update: As of the time of this writing (6/12/2013), the latest release from the Federal Reserve reports Baa bond rates on June 7, 2013 to be 5.06%, and the average for May 2013 to be 4.73%). The optimistic case was set equal to the prime rate, as reported by the Federal Reserve (http://www.federalreserve.gov/releases/h15/data.htm) during the time period that the sensitivity analysis initially was developed (late January) (3.25%) less the average forecasted long-run inflation rate in the "Headline CPI," as reported in the Federal Reserve Bank of Philadelphia's Survey of Professional Forecasters, Release date: November 9, 2012, available from http://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/ (2.28%). (Update: As of the time of this writing (6/12/2013), the prime rate had held steady at 3.25%, and the latest release of the Survey of Professional Forecasters, May 10, 2013, reported the average forecasted long-run inflation rate in the "Headline CPI" to be 2.3%.) The pessimistic case value was set equal to the sum of the optimistic and base case values.

[xxiii] Base case capital cost based on: RICL's October 10, 2012 Petition to the Commission (p. 24, paragraph 45; p. 28, paragraph 55); the testimony of RICL witness Michael Skelly (RICL Ex. 1.0, p. 33, lines 775-776); and the supplemental testimony of RICL witness David Berry (RICL Ex. 10.13, p. 3, lines 69-70 and 87-90). Capital costs under the pessimistic and optimistic cases are, relative to the base case, 20% higher and 20% lower, respectively.

[xxiv] The same nominal inflation rates are used for both electric energy and capacity prices. The base case inflation rate is based on adding 2.5% (the assumed general inflation rate used in this analysis) to the 2013 EIA AEO Early Release forecast of real electric generation cost price increases from 2011-2040, which was 0.7%. The pessimistic and optimistic cases are, relative to the base case, 1% greater and 1% lower, respectively. (Update: The April 15, 2013 release of the 2013 EIA AEO forecast shows that the reference case forecast of real electric generation cost price increases did not change from the 0.7% shown in the Early Release. In examining the 26 other cases developed by the EIA, they vary from 0.8% below the reference case to 1.1% above the reference case.).

[xxv] Useful life of power plants based on review of various sources, most of which support a useful life of wind turbines of 20 years, but others report ranges of 20-25 years, 20-30 years, and one source as low as 15 years. Erring on the slightly optimistic side, the base case value used in this sensitivity analysis is assumed to be 25 years, with the optimistic and pessimistic cases assumed to be plus and minus 4 years on either side of the base case. In all cases, the present value of additional revenue requirements needed by the power plants was computed for a 40 year period, to match the assumed useful life of the RICL project. For example, when a 25-year power plant life is assumed, the discounted value of revenues for the first wave of power plants, collected over the first 25 years, is added to the discounted value of revenues for the second wave of power plants, collected over the next 15 years.

[xxvi] Wind Farm costs based on EIA 2013 Early Release, assumptions used in the Electricity Module, Table 8.2. (Update: EIA's April 2013 Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants shows the same values as the Early Release assumptions, except they have been adjusted from 2011$ to 2012$.) High case wind farm cost inflation rate based roughly on long term trends shown in the LBNL 2011 Wind Technologies Report. In the high case, wind farm costs increase at the same rate as general inflation, so in real (inflation adjusted) terms, they remain constant. Base case for wind farm cost inflation rate based roughly on more recent trends shown in LBNL 2011 Wind Technologies Report, and is 0.4 times the High Case. The Low Case is 0.4 times the base case.

[xxvii] The impact of building wind farms in Iowa without the addition of the RICL Project on the capacity factor of Iowa wind farms and the average locational marginal prices of electricity in Iowa were set arbitrarily, to illustrate the potential significance of these factors.

[xxviii] For a discussion of the Illinois wind farm capacity factors used in the sensitivity analysis, see Zuraski direct testimony.

[xxix] Natural gas price cases based on EIA 2013 AEO April Release forecasts of real natural gas prices for Electricity Producers in the East North Central Region (within which Illinois resides). These were adjusted to nominal dollars with the constant 2.5% general inflation rate assumed in the sensitivity analysis (see note ii). Beyond 2040, prices increased by the average annual increase between 2012 and 2040 and by the constant 2.5% general inflation. The base case, low case, and high case are the average, the minimum, and the maximum forecasts among the 27 scenarios modeled by the EIA. The average used for the base case ranges from 4% to 16% greater than EIA's reference scenario.

[xxx] Combined cycle power plant costs base case based on EIA 2013 Early Release, assumptions used in the Electricity Module, Table 8.2. The pessimistic case based on 2012 EIA AEO assumptions, with costs escalated by CPI from 2010$ to 2011$. The optimistic case assumes a 1% improvement relative to the base case (which is roughly symmetrical with the pessimistic case around the base case). (Update: EIA's April 2013 Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants shows the same values as the Early Release assumptions, except they have been adjusted from 2011$ to 2012$.)