West Hants
something inspiring awaits

WEST HANTS REGIONAL MUNICIPALITY
Climate Action Committee Agenda
April 9, 2025 – 11:00am
Council Chambers / Zoom and YouTube Live

1.0 Call to Order and Identification of Designates

2.0 Approval of Agenda and Additions

3.0 Approval of Minutes (February 26, 2025)

4.0 New Business

4.1 Recommendation: CAC Terms of Reference Amendments (John Ogilvie)

4.2 Information: Solar PV Feasibility Study (John Ogilvie)

5.0 Business Arising from the Minutes

5.1 Update: Climate Change and Health Vulnerability Assessment (John Ogilvie)

5.2 Update: NSPI Level 3 EV Chargers (John Ogilvie)

6.0 Roundtable Discussion

7.0 Public Comments

8.0 Next Meeting Date (September 10, 2025)

9.0 Adjournment

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WEST HANTS REGIONAL MUNICIPALITY REPORT

Information ☐	Recommendation ☒	Decision Request ☐	Councillor Activity ☐

To: Climate Action Committee (CAC)

Submitted by: ___________________________________
John Ogilvie, Climate Action Coordinator

Date: 2025-04-09

Subject: Amendments to the CAC Terms of Reference

LEGISLATIVE AUTHORITY

CAC Work Plan, Ongoing Tasks

Meeting and Committee Procedural Policy, Section 17.3(j)

RECOMMENDATION

…that the Climate Action Committee recommend that Council approve the amendments to the Committee's Terms of Reference, as shown in Attachment A to the report "Amendments to the CAC Terms of Reference", dated April 9, 2025.

BACKGROUND

Property ☐	Public Opinion ☐	Environment ☒	Social ☐	Economic ☐	Councillor Activity ☐

Staff are preparing to bring forward recommended amendments to the *Meeting and Committee Procedural Policy* at the Council meeting on April 22, 2025, unrelated to the CAC Terms of Reference (TOR). With this information, I considered it prudent to bring housekeeping amendments to the CAC TOR forward at the April 9, 2025, meeting, so they can be considered for approval by Council on April 22, 2025.

DISCUSSION

The recommended amendments to the CAC TOR are presented in red in Attachment A; many of the suggestions are to fix grammatical errors or typos. A list of substantial suggested amendments, such as additions and word replacements, is below in Table 1.

Table 1: Substantial CAC TOR Amendments Compared to Existing Version

Section	Recommended	Existing
3. Goals	"…the adaptation and mitigation actions outlined in the Municipal Climate Change Action Plans (MCCAP) and the Greenhouse Gas (GHG) Emission Local Action Plan of the Municipality."	"…the adaptation and mitigation actions outlined in the Municipal Climate Change Action Plans of the Municipality hereafter referred to as "the MCCAP"."
4. Deliverables	"The Committee will: • develop an annual work plan of actions based on the MCCAP and GHG Emission Local Action Plan. This work plan will include the estimated timeline and cost for the action, anticipated partners, and recommendations for funding sources such as the Canada Community Building Fund or other provincial and federal funding programs. The annual work plan will summarize actions completed in the previous year; • submit the work plan annually to Council to be placed on file; • keep Council fully informed on the progress of MCCAP and GHG Emission Local Action Plan implementation; and • undertake, as it determines appropriate, pilot projects that carry out actions outlined in the MCCAP and GHG Emission Local Action Plan, funded in part or in	"The Committee will: • develop an annual Work Plan of actions based on the MCCAP. This work plan will include the estimated timeline and cost for the action, anticipated partners, and recommendations for funding sources such as the Gas Tax Agreement or other provincial and federal funding programs. The annual Work Plan will summarize actions completed in the previous year; • submit the Work Plan annually to Council to be placed on file; • keep Council fully informed on the progress of MCCAP implementation; • undertake, as it determines appropriate, pilot projects that carry out actions outlined in the MCCAP, funded in part or in whole through the Committee's approved annual budget;"

	whole through the Committee's approved annual budget."	
7. Governance	"Orders and rules of conduct for debate for CAC meetings are the same as those for Council in the *Meeting and Committee Procedural Policy*."	"Orders and rules of conduct for debate for MCCAP meetings are the same as those for Council in the Meeting and Committee Procedural Policy."
8. Communications	"All CAC meetings are open to the public, except as specified Section 203 of the *MGA*. ~~CAC agendas may set aside a period of time during the meeting for public comment or presentation.~~"	"All CAC meetings are open to the public, except as specified Section 203 of the *MGA*. CAC agendas may set aside a period of time during the meeting for public comment or presentation."
9. Related Policies, Procedures and Legislation	West Hants Regional Municipality GHG Emission Local Action Plan West Hants MCCAP Hantsport MCCAP Windsor MCCAP West Hants ICSP Hantsport ICSP Windsor ICSP Meeting and Committee Procedural Policy Council Remuneration Policy	West Hants MCCAP Hantsport MCCAP Windsor MCCAP West Hants ICSP Hantsport ICSP Windsor ICSP Meeting and Committee Procedural Policy Council Remuneration Policy

As shown in Table 1 above, many of these recommended edits involve adding the WHRM GHG Emission Local Action Plan to the Committee's referenced plans, deliverables, and goals – as this plan guides much of the Municipality's climate action work in conjunction with the MCCAPs. This also includes adding that document as a related policy in Section 9.

Section 7 Governance still included a reference to the MCCAP Committee, which is the former name of the Committee, so it has been changed to refer to it as the CAC. Another important change is removing the last sentence in Section 8 Communications. This change is recommended to align the TOR with the *Meeting and Committee Procedural Policy*, which governs public participation periods at Council and Committee meetings.

NEXT STEPS

If the CAC makes the above recommendation:

- staff will prepare a recommendation report for the Council meeting scheduled for April 22, 2025; and

- pending Council approval, staff will publish the updates to the TOR to the municipal website.

FINANCIAL IMPLICATIONS

There are no financial implications associated with the filing of this report, or the recommended changes to the CAC TOR.

ALTERNATIVES

The Committee may:

- opt to not make the recommendation;
- make the recommendation with specific changes as directed by the Committee; or
- request further information on a specific topic.

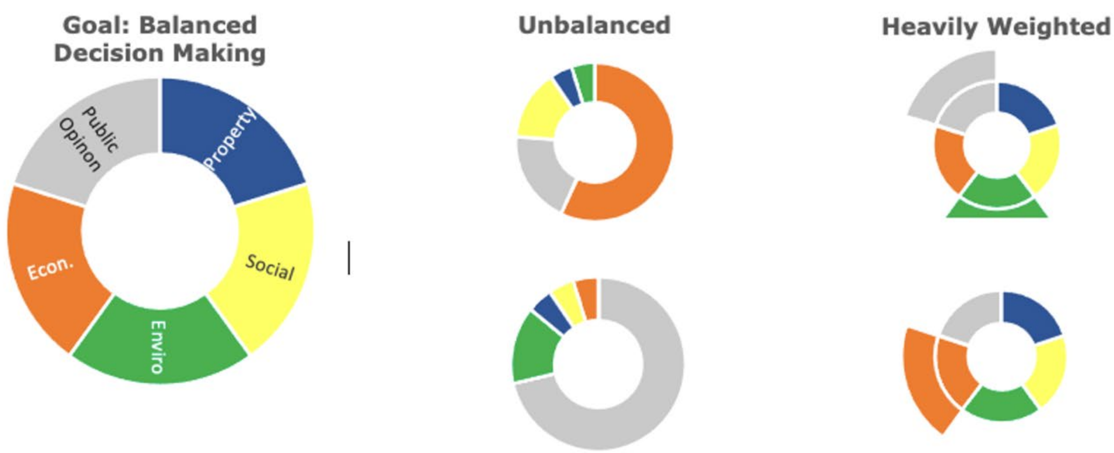
ATTACHMENTS

Attachment A *Climate Action Committee Terms of Reference* with Recommended Amendments

Attachment B WHRM *Meeting and Committee Procedural Policy*

REVIEW

The Committee has been provided with a reference taken from the *Meeting and Committee Procedural Policy*, Appendix C "Decision Making by Council and Committee of the Whole", as a reminder of the principles highlighted for good decision making.



Report Prepared by: ___________________________________

John Ogilvie, Climate Action Coordinator

Report Approved by: ___________________________________
Kari Fougere, Acting Director of Planning and Development

WEST HANTS REGIONAL MUNICIPALITY
CLIMATE ACTION COMMITTEE
TERMS OF REFERENCE

RADPL-003.04

1. Official Name

The official name of this committee is the Climate Action Committee. It may be referred to as the CAC.

2. Members/Composition

The Committee consists of eleven (11) members:

- three (3) Councillors;
- two (2) resident members, who are not members of Council
- Chief Administrative Officer or designate;
- Director of Public Works or designate;
- Director of Planning and Development or designate;
- Director of Community Development or designate;
- Director of Finance or designate;
- Protective Services Manager or designate.

All members of the Committee are appointed by resolution of Council, and each member appointed serves the Committee for a two-year term. Members are eligible for reappointment.

Resident members are chosen through an evaluation process and recommendation to Council.

All positions, whether or not an existing member has re-offered, will be reviewed through the evaluation process when the specified term is over.

In the case of an unexpected vacancy, previous applications on file may be considered by the Chair and staff, or the option to re-advertise may be applicable. A recommendation will be made to Council for appointment. That new person's appointment will serve the remainder of the term of the person replaced or as deemed appropriate.

The Chair and the Vice-Chair are elected by a majority of the members and hold office for a two-year term. The Chair acts as the liaison with Council.

The CAC may recommend to Council that a Committee member who fails to attend three (3) consecutive meetings of the CAC, without good reason accepted by the CAC Chair, be dismissed from the Committee.

3. Goals

The Climate Action Committee provides a forum for all municipal departments and Council representatives to work co-operatively on implementing and evaluating the adaptation and mitigation actions outlined in the Municipal Climate Change Action Plans (MCCAP) and the Greenhouse Gas (GHG) Emission Local Action Plan of the Municipality ~~hereafter referred to as "the MCCAP"~~. These policy and adaptation procedures help protect people, properties, special places, and municipal infrastructure from the negative impacts of climate change.

The Committee will strive to reflect the best interests of the Region in any recommendation.

4. Deliverables

The Committee will:

- develop an annual w~~W~~ork p~~P~~lan of actions based on the MCCAP and GHG Emission Local Action Plan. This work plan will include the estimated timeline and cost for the action, anticipated partners, and recommendations for funding sources such as the Canada Community Building Fund ~~Gas Tax Agreement~~ or other provincial and federal funding programs. The annual w~~W~~ork p~~P~~lan will summarize actions completed in the previous year;
- submit the w~~W~~ork p~~P~~lan annually to Council to be placed on file;
- keep Council fully informed on the progress of MCCAP and GHG Emission Local Action Plan implementation; and
- undertake, as it determines appropriate, pilot projects that carry out actions outlined in the MCCAP and GHG Emission Local Action Plan, funded in part or in whole through the Committee's approved annual budget~~;~~.

5. Jurisdiction

The CAC was formed pursuant to the *Meeting and Committee Procedural Policy* dated March 23, 2020.

The Committee's duration is indefinite, based on~~:~~ Council's continued support of the above Goals and Deliverables.

- ~~Council's continued support of the above Goals and Deliverables.~~

6. Resources/Budget

Following their appointment, new Committee members will be given an introductory workshop organized by staff to assist them in their duties.

CAC resident members are remunerated in accordance with the Councillor Remuneration Policy.

Municipal planning staff will provide ongoing support to the Committee. Staff will:

- arrange meeting times and venues and take Committee minutes;
- circulate meeting agendas and minutes;
- provide reports or status updates on identified projects or applications; and
- make public presentations on behalf of the Committee as required.

7. Governance

CAC meetings will generally take place the morning of the second Wednesday of the month in February, April, September, and November but additional meetings may be called by the Chair on an as-needed basis or as directed by Council. Members will be informed of all meetings and supplied with an agenda prior to each scheduled meeting date.

A quorum is a majority of the number of appointed members at the time of the meeting.

Orders and rules of conduct for debate for ~~MCCAP~~ CAC meetings are the same as those for Council in the *Meeting and Committee Procedural Policy*.

8. Communications

CAC members and staff will communicate with each other at meetings (in person or electronic), by telephone or by email.

Draft minutes of CAC meetings are available to the public and will be approved at the next meeting.

All CAC meetings are open to the public, except as specified Section 203 of the *MGA*.

~~CAC agendas may set aside a period of time during the meeting for public comment or presentation.~~

9. Related Policies, Plans, Procedures and Legislation

West Hants Regional Municipality GHG Emission Local Action Plan
West Hants MCCAP
Hantsport MCCAP
Windsor MCCAP
West Hants ICSP
Hantsport ICSP
Windsor ICSP
Meeting and Committee Procedural Policy
Council Remuneration Policy

Approved by: _______________________________
Committee Chair

Adoption	
Notice to Council:	Not Applicable
Approval:	September 9, 2020
Description: Initial approval of the MCCAP Committee Terms of Reference	
1st Amendment	
Notice to Council:	Not Applicable
Approval:	February 9, 2022
Description: Amended MCCAP Committee Terms of Reference	
2nd Amendment	
Notice to Council:	*Not Applicable*
Approval:	*January 23, 2024*
Description: Amended MCCAP Committee Terms of Reference: Changed Committee name	

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1. <u>General</u>

1.1. This Policy will be known and cited as the "Meeting and Committee Procedural Policy".

1.2. The purpose of this Procedural Policy is to:

a) provide direction to Council and Staff members on conducting Council and Committees of Council meetings. This Policy does not apply to boards, commissions and committees of which the Municipality may be a member, but which was not established solely by the Municipality;

b) establish the Committee of the Whole as a Committee of Council; and

c) establish various other Committees of Council.

1.3. In this Policy:

a) "Act" means the Municipal Government Act, Stats. N.S. 1998, C. 18

b) "Business day(s)" means a day which the administrative offices of the Municipality are open for business;

c) "Chair" means the presiding officer of Council or a Committee of Council;

d) "Chief Administrative Officer" or "CAO" means the Chief Administrative Officer of the Municipality;

e) "Clerk" means the Clerk of the Municipality;

f) "Closed Meeting" means a meeting which is not open to the public and may be known as in-camera.

g) "Committee of Council" means a committee formed pursuant to a resolution or policy of Council;

h) "Council" means all Council members of the Municipality;

i) "Councillor" means a Council member and includes the Mayor and Deputy Mayor unless the context indicates otherwise;

j) "Electronic means" the use of any technology that enables the public and all meeting participants to see and hear each other as the meeting is occurring.

k) "Majority" means more than one-half of those present

l) "Meeting Package" means the package prepared for a meeting consisting of the agenda and associated agenda item material;

m) "Motion" means the formal mode in which a Council member submits a proposed measure or resolve for the consideration and action of Council or Committee of Council;
n) "Municipal or Municipality" means the West Hants Regional Municipality;
o) "Pecuniary interest "means a situation where there is a reasonable likelihood or expectation of appreciable financial loss or gain to the person, or to other persons;
p) "Planning document" means a Municipal Planning Strategy, Land Use By-law, or Subdivision By-law;
q) "Question" means the subject matter of a motion; when the question is called, the motion is put to a vote without further debate;
r) "Quorum" means the majority of members required to hold a meeting.
s) "Resolution" means a formal expression of the opinion or the will of the Council or a Committee of Council adopted by vote, and is a result of an approved motion;
t) "Staff" means a person employed by the Municipality;
u) "Two-thirds vote" means a vote where at least two-thirds of the members present and entitled to vote at the meeting vote in favor of the motion.

2. <u>Mandate of Council and Committee of the Whole</u>

2.1. The mandate of Council is:

a) to exercise the powers of the Municipality as set out in the *Act* through the approval of motions, policies and by-laws;
b) to provide strategic planning for the Municipality with the goals:
   i. to provide good government;
   ii. to provide services, facilities and other things that in the opinion of Council are necessary or desirable for all parts of the Municipality;
   iii. to develop and maintain safe and viable communities;
   iv. to work with other municipal units for the best interests of the Municipality within the province.
   v. to provide active programs of training and upgrading of staff and Council; and
   vi. such other goals as from time to time are determined;
c) to conduct the official business of the Municipality;
d) to carry out any statutory public hearings as required by the *Act* and other legislation;
e) to provide strategic direction to the CAO through resolutions, policies and by-laws

2.2. The mandate of the Committee of the Whole is:

a) to discuss, consider, advise and make recommendation to Council for approval concerning the affairs of the Municipality in advance of Council making decisions or taking actions on such matters, except where Council has determined that consideration by Committee of the Whole is unnecessary or inadvisable, and except that the following matters will normally be dealt with by Council without having to be forwarded to the Committee of the Whole for its recommendations:

i. first and second readings of a by-law enactment, amendment or repeal; and

ii. matters which are the subject of statutory hearing of Council;

b) to carry out the duties and responsibilities of Council set forth in Part XV Dangerous and Unsightly Premises of the *Act*;

c) to carry out the duties of the Regional Emergency Management Advisory Committee as set forth the Regional Emergency Management By-law of the Municipality;

d) to take such steps not inconsistent with this Policy that the Committee of the Whole reasonably deems necessary to carry out this mandate;

e) except for an Order under the Act for Dangerous and Unsightly Premises and specific tasks or matters assigned by Council from time to time to the Committee, all resolutions of the Committee of the Whole will be recommendations to Council for Council's approval.

3. <u>Time, Place, Date and Notice of Meetings</u>

3.1. All meetings of Council and Committees of Council will be public meetings, except as provided for under Sections 22 (2) and 203(1) of the Act and Section 14 of this Policy.

3.2. Unless otherwise specified pursuant to Section 3.5 of this Policy a regular meeting of the Committee of the Whole will be held:

a) at the location set by the Committee of the Whole,

b) on the second Tuesday of each month, except for August,

c) commencing at 6:00 p.m. unless otherwise directed by Council.

3.3. Unless otherwise specified pursuant to Section 3.5 of this Policy, a regular meeting of Council will be held:

a) at the location set by Council,

b) on the fourth Tuesday of each month except for August,

c) commencing at 6:00 p.m. unless otherwise directed by Council.

3.4. Unless otherwise specified pursuant to Section 3.5 of this Policy, regular meetings of other Committees of Council will be determined in the Administrative Terms of Reference for the Committee.

3.5. Meetings may be rescheduled, relocated or cancelled:

a) by resolution or consensus, including a contingent resolution or consensus of Council or a Committee of Council at a previous meeting three (3) or more business days in advance of the meeting;

b) at the request of majority of the members of Council or Committee of Council;

c) by the CAO or designate on behalf of the Mayor, Deputy Mayor or Chair, due to inclement weather or unforeseen circumstances provided the Mayor, Deputy Mayor, or Chair believes the majority of members would support such a step.

3.6. Additional or special meetings of Council or a Committee of Council may be convened:

a) by resolution or consensus, including contingent resolution or consensus of Council or Committee of Council at a meeting three (3) or more business days in advance of the additional or special meeting;
b) at the request of the Chair;
c) at the request of the majority of members;
d) by the CAO or designate on behalf of the Mayor, Deputy Mayor or Chair, due to unforeseen circumstances, provided the Mayor, Deputy Mayor or Chair believes that the majority of members would support such a step; or
e) where the Mayor determines there is an emergency, Council may meet without notice or with such notice as is possible in the circumstances

3.7. Notice to Councillors and the Public of meetings:
a) subject to any statutory relaxation of the notice requirements, at least three (3) business days' notice to Councillors will be provided for additional or special meetings by telephone, the email address provided by the Municipality or other email address, fax number or messaging service;
b) subject to any statutory relaxation of the notice requirements, at least two (2) business days' notice to the public will be provided for additional or special meetings by posting a notice of the meeting on the Municipal website and social media pages;
c) Councillors and the public will be deemed to have received any notice within one (1) day of being notified pursuant to this section;
d) meeting notice need not be provided of:
   i. regular meetings held pursuant to Sections 3.2 and 3.3 of this Policy;
   ii. regular meetings of a Committee of Council whose regular meeting date is contained in a policy or by-law of Council or posted on the Municipal website; or
   iii. meetings held pursuant to Sections 3.5 (a) and Section 3.6 (a) of this Policy;
e) notice of meeting cancellations will be provided to Council and the public as soon as possible in the same manner;

3.8. In accordance with Section 19 (7)(a)(b) of the Act no meeting of Council or Committee of Council is illegal or invalid by failure to give notice or by meeting elsewhere than provided in this Policy or the notice of meeting.

3.9. Within thirty (30) days following the first meeting of Council after an election or by-election each Councillor will provide the Clerk the following:
a) a telephone number with answering machine/voicemail which the Councillor has and will maintain and will check at least once per day;
b) the unique email address provided by the Municipality, where all municipal notices and correspondence will be forwarded and which the Councillor will check at least once per day;

c) any other email address, fax number, or messaging service which the Councillor has and will maintain and will check at least once per day.

4. <u>Communications</u>

4.1. The Mayor is the official spokesperson of Council and the CAO is the official spokesperson of staff.

4.2. Council communication to the public is:

a) through the Mayor, as the official spokesperson for the Municipality regarding decisions approved by Council unless another Councillor is designated;

b) through Councillors as chief spokespersons for explaining policies, priorities and decisions; and

c) through Committee Chairs as chief spokesperson for matters dealt with under the authority of their committee, unless another Councillor is designated;

d) media interview requests will be referred to the Mayor or the CAO to determine who is the most appropriate spokesperson for the interview.

4.3. Council communication to staff is:

a) through a resolution of Council or Committee of Council for advice, information or recommendations on matters which require thoughtful research and review. Staff will normally provide their response through a written information or recommendation report like that in Appendix A;

b) through resolutions from Council to the CAO.

4.4. Committees will communicate to Council:

a) through a written information or recommendation report by Chairs to Committee of the Whole like that found in Appendix A.

b) where all Councillors are members; may communicate using excerpts sheets of the motions being recommended to go straight to Council with the previous committee report (referred to in the excerpt), attached as a supporting document.

4.5. All Councillors are expected to provide a monthly report to Council stating the Municipal business they were involved in over the previous month, using the report form in Appendix A.

4.6. The CAO or designate may, on behalf of Council or Committee of Council, receive correspondence from the public and deliver a copy of the correspondence to all Councillors within a reasonable time provided:

a) the correspondence is directed to a Councillor or Committee of Council member;

b) is in writing and received by mail or email;

c) is legible;

d) is not libelous, irrelevant, offensive or improper; and

e) is signed by the writer's name.

5. Meeting Attendance and Quorum
   - 5.1. Councillors are expected to attend all meetings of Council and Committees of Council to which they are appointed.
   - 5.2. Subject to changes of the Act Section 17 (4), Councillors who without leave of Council are absent from three (3) consecutive regular meetings of Council ceases to be qualified to serve as a Councillor.
   - 5.3. Councillors who without leave of a Committee of Council and are absent from three (3) consecutive regular meetings of a Committee of Council to which they are appointed, may be removed from the Committee. This also applies to resident members appointed to a Committee of Council.
   - 5.4. Council or a Committee of Council will not refuse the leave of a Councillor if such leave is due to employment issues, illness, other Municipal business, or an unforeseen event needing immediate attention.
   - 5.5. Sections 5.1, 5.2 and 5.3 do not apply to Councillors on a parental accommodation leave of absence in accordance with Section 17 (4A) of the Act.
   - 5.6. Quorum for meetings of Council and Committee of the Whole will be the majority of elected Councillors, or seven (7) Councillors.
   - 5.7. Quorum of other Committees of Council will be the majority of the voting members unless otherwise stated in a policy or by-law of Council or administrative terms of reference.
   - 5.8. A Council meeting or Committee meeting may be conducted by electronic means pursuant to Section 19A (1) of the MGA.
     - a) One or more Council or Committee members participating in a meeting by electronic means is deemed to be present at the meeting for purposes of quorum and voting.
     - b) Except as provided in section 5.8, all attempts will be made for a Councillor(s) or Committee members to attend meetings in-person.
     - c) Council or Committee members will provide sufficient notice to the Chair or Clerk (prior to the meeting) of the circumstances that prevent them from attending the meeting in person. This notice should clearly indicate that the circumstances are beyond the control of the Council or Committee member, and that all reasonable efforts have been made to resolve the situation so that they are able to attend the meeting in-person.
     - d) It is the responsibility of the Councillor or resident member to ensure provision of electronic means at their location;
     - e) If used during a closed meeting, the member will ensure confidentiality is maintained at all times;
     - f) Every intention will be made that no Councillor or resident member participates by electronic means in no more than four (4) regularly scheduled meetings per year; with the awareness that emergencies occur.

g) The Councillor, resident member or members of the public does not interfere and/or disrupt the meeting, and if such occurs the Chair has the right to end the electronic participation

5.9. All Councillors or resident members of Committees of Council may participate by electronic means as described in 5.8 during a local and/or world-wide crisis, or when determined by the Mayor or designate that a meeting occur to tend to an emergency or time sensitive matter. This would not count towards the four (4) electronic meetings per year as identified in 5.8(g).

5.10. If a quorum is not present fifteen (15) minutes following the scheduled start time of a meeting and it is deemed not reasonable that quorum will be present within a reasonable time, the meeting will be cancelled and a record of the cancellation along with the names of the members present will be recorded in the minutes.

5.11. Where there is a permanent vacancy on Council or a Committee of Council, Councillors may make a decision if a quorum is present at the meeting.

5.12. If the number of Council members is reduced to below the number required for a quorum due to vacancies in Council, Council may not pass a by-law or policy, borrow money, set a tax rate, acquire or sell property, for make any other decision that has an effect after or for a term extending beyond the date of the election to fill a vacancy on Council

6. <u>Election Process for Deputy Mayor, Chair or Vice-Chair</u>

6.1. At the first meeting of Council held on the first available date no earlier than 10 days and not later than 4 weeks after ordinary polling day, all Councillors will be sworn in and the Deputy Mayor will be elected as follows:

a) the Mayor will call the meeting to order and call for nominations for the position of Deputy Mayor three times;

b) Councillors may nominate themselves or a fellow Councillor for the position of Deputy Mayor, but may not nominate themselves; nominations do not have to be seconded;

c) after the third and final call for nominations, the Mayor will declare nominations closed;

d) the Mayor will ask each nominee if they accept the nomination for Deputy Mayor;

e) if only one Councillor was nominated and accepted the nomination, that Councillor is declared the Deputy Mayor;

f) if there is more than one nominee, the Mayor will provide each of the nominees an opportunity to speak and Councillors will elect the Deputy Mayor by secret ballot;

g) two volunteers are asked to be scrutineers, one of which must be a staff member. Ballots are distributed to Councillors, votes will be cast, then the scrutineers will collect and count the ballots;

h) the scrutineers announce the overall result of the election (not the number of votes for each Councillor). The Deputy Mayor is determined by majority of the number of Councillors present;

i) if there is not a winner by majority and there are three (3) or more nominees, another vote will occur by dropping the nominee with the lowest votes and voting again until only two (2) nominees remain. If there is not a winner by majority and there are only two (2) nominees, the Deputy Mayor will be determined by a draw by the Clerk or designated staff member.

j) once the Deputy Mayor has been declared elected, a motion will be made to destroy the ballots.

6.2. The term of office for the Deputy Mayor will be two (2) years.

6.3. The election of a Chair for a Committee of Council will be completed in a similar manner to the election of the Deputy Mayor except that a staff member will perform the duties of the Chair until the Chair of the Committee of Council is elected. Nominees for Chair will be given an opportunity to speak to the members of the Committee of Council before the vote is held.

6.4. Once a Chair of a Committee of Council is elected, they may perform the election in the same manner for a Vice-Chair.

6.5. The term of office for a Chair or Vice Chair will be two years unless otherwise stated in a policy of Council or administrative terms of reference.

7. <u>Meeting Agendas and Packages</u>

7.1. At Council meetings, unless a majority consents to a different order for that meeting, business will be conducted in the following order:

a) Call to Order
b) Attendance
c) Approval of Agenda, including additions or deletions and Dashboard items
d) Declaration(s) of Conflict of Interest
e) Announcements
f) Approval of previous meeting's minutes
g) Public Hearings
h) Unfinished Business/Postponed Motions
i) Mayor's Report
j) Committees of Council Recommendations
k) Councillor Municipal Business Reports
l) Correspondence
m) New Business
n) In-Camera
o) Next Meeting Date / Adjournment

7.2. At Committee of the Whole, unless a majority consents to a different order for that meeting, business will be conducted in the following order:

a) Call to Order
b) Attendance
c) Approval of Agenda, including additions and deletions and Dashboard items
d) Declaration(s) of Conflict of Interest
e) Announcements
f) Approval of the Minutes
g) Presentations
h) Unfinished Business/Postponed Motions
i) Reports
j) Correspondence
k) New Business
l) Public Participation Period
m) In-Camera
n) Next Meeting Date / Adjournment

7.3. Agendas of other Committees of Council and Public Hearings will be determined as needed or detailed in the Committee's Administrative terms of reference.

7.4. All topics and supporting material for an agenda will be submitted to the staff member preparing the agenda by 12:00 noon five (5) business days before a regular scheduled meeting. Councillors will be required to submit a "Report Form" (Appendix A) to be included in the agenda package.

7.5. All agendas will be approved by the Mayor or Chair of the Committee of Council and the CAO or designate.

7.6. All agenda items must have an associated report, excerpt sheet, and/or other material outlining the purpose and background of the agenda item put together in one PDF document.

7.7. Meeting packages will be provided to Councillors and resident members of Committees of Council by 5:00 p.m. at least three (3) business days before the meeting by internal communication systems or email.

7.8. Meeting packages will be provided to the public by 5:00 pm two (2) business days before a meeting by posting the meeting package to the Municipal website.

7.9. Meeting packages for a special meeting of Council or a Committee of Council will be provided to Councillors, resident members and the public in accordance with Sections 7.7 and 7.8 should time permit, or by 12:00 noon one (1) business day before the special meeting.

7.10. If an agenda item's associated material is not distributed in the meeting package and the majority of Council accept the report it will be distributed electronically or by hard copy during or after the meeting.

7.11. Late additions to the agenda will be accepted if approved by the majority of Council at the meeting. No late additions will be accepted for special meetings.

7.12. Agenda items may also be added at the meeting if it is time sensitive or concerning a matter where life, property or the environment is at immediate risk and cannot be dealt with at a later meeting once approved by the majority of Council. All meeting package material for these items will be distributed electronically or by hard copy during or after the meeting.

7.13. For instances when a requested agenda item may be outside the jurisdiction of the Municipality, require more research, or should be dealt with in a different forum or meeting, the Mayor or Chair will have the authority to delete, defer, or refer the agenda item. The Mayor or Chair will advise the person requesting the agenda item of the action taken.

7.14. All material in a meeting package which is posted on the Municipal website will be deemed received at the time of agenda approval during the meeting. All material not publicly posted that is read or visually presented during the meeting will be deemed received and amended to the posted meeting package posted on the Municipal website.

7.15. Once an agenda item has been dealt with it should not be put on the agenda again for at least six (6) months unless there is a follow up report on actions taken, or a proper motion is made to reconsider, rescind or amend something previously adopted.

8. <u>Council and Committee Chair Duties</u>

8.1. The Chair of Council will be the Mayor and the Chair of Committee of the Whole will be the Deputy Mayor except:

a) in the absence of the Mayor, the Deputy Mayor will be the Chair
b) in the temporary absence of both the Mayor and Deputy Mayor, a Chair will be appointed from the Councillors present at the meeting.

8.2. The Chair of a Committee of Council will be the Councillor or resident member elected and, in their absence, the Vice-Chair elected.

8.3. It will be the duty of the Chair to:

a) open the meeting by taking the chair and calling the members to order and announcing the business before Council or the Committee of Council;
b) ask members to declare any Conflicts of Interest;
c) receive and put to a vote all motions presented and announce the results;
d) decline to put to a vote a motion which infringes upon rules of procedure established by this Policy;
e) restrain Councillors when engaged in debate, within the rules of conduct established by this Policy or Robert's Rules of Order;

f) protect the rights of those attending the meeting and enforce the rules of order; preserve order, and decide on point of order;

g) call by name any Councillor or resident member persisting in a breach of this Policy, and thereby ordering them to vacate the meeting room;

h) permit the CAO to speak on any point upon request;

i) permit staff and invited guests to speak when appropriate on the agenda and at the request of Councillors and/or CAO;

j) permit proper questions to be asked through the Chair of any Councillor, CAO, staff member, or invited guest in attendance relevant to the issue under discussion in order to provide information to assist debate;

k) declare a meeting dissolved if no quorum has been achieved;

l) adjourn to another place and/or time without ending the meeting with the consent of Council;

m) adjourn the meeting when the business is concluded and a motion to adjourn has been approved by the majority vote; or

   i. adjourn the meeting when an adjournment time has been set and approved by majority vote or consensus, when the time has been reached except when it is extended by unanimous consent; or

   ii. adjourn the meeting at the Chair's sole discretion due to inclement weather conditions to a time and date set by the Chair.

9. <u>Minutes and Recordings</u>

9.1. Written minutes of Council and all Committee of Council meetings, including in-camera meetings, will be kept providing a permanent and historical record of the Municipality's business. When required, these minutes may be recognized in court as evidence of decisions made and actions taken.

9.2. Written minutes kept will:

a) record the names of the members or participants and the time when any member joins or leaves a meeting which is in progress;

b) contain all motions and decisions by consensus and will record the outcome of each vote;

c) record the names of all Councillors or resident members who voted "Nay" to a motion put to a vote;

d) summarize key points of a discussion and mention reports, petitions, correspondence, presentations and other papers submitted only by their respective title, or a brief description of the content;

e) contain presentation points and timestamps of when the reports were discussed during the meeting.

f) be clear, accurate, concise, and formatted to be readable;
g) be written in past-tense;
h) flow logically in accordance with the agenda, even if the meeting itself had been fragmented and confusing.

9.3. To assist with accurate composition of draft minutes, public meetings of Council or Committees of Council (including In-Camera sessions) will be recorded using audio recording equipment. Once minutes are approved, the audio recording will be kept for at least seven (7) years after which it may be destroyed in accordance with the Records Management Policy of the Municipality

9.4. Draft minutes of Council and Committee of the Whole will be reviewed by the Clerk and CAO. Informational sessions hosted by the Municipality will be recorded using audio and video equipment to accurately reflect information sharing. These meetings will be later uploaded to the Municipal Facebook page for transparency. No written minutes will be available for these meetings.

9.5. Draft minutes of other Committees of Council will be reviewed in accordance with the Committee of Council's Administrative Terms of Reference.

9.6. Minutes of all meetings will be posted in draft electronic form on the Municipality's website for the public and to the internal communication system for Councillors and staff for information.

9.7. The minutes of the last preceding regular meeting and subsequent special meetings will be reviewed at the next meeting of Council or Committee of Council and after all necessary corrections and amendments have been noted, be approved and signed by the Mayor or Chair.

9.8. To correct the minutes at the time of approval, the word or words will be crossed out and the corrections written in and initialed before being signed by the Chair. The digital form of the minutes posted to the Municipality's website and internal communication system will be changed accordingly in red font and a footnote of the changes will be added to the electronic minutes stating "Amended".

9.9. A request for copies of the audio recordings of public meetings may be submitted in writing or electronic mail to the Clerk of the Municipality and will be provided, if available, for a prescribed fee

9.10. Council and Committees of Council may choose to live-stream video on the internet of any or all meetings, with no obligation to live-stream video of a meeting. Should technical difficulties arise and livestreaming not be enabled or if livestreaming is not possible, the meeting will continue as scheduled. There will be no audience participation/comments using the live-streamed video. Commenting on livestream videos have ben turned off.

9.11. Except for Section 9.3, 9.9 and 9.11 of this Policy, electronic means recordings and the taking of photos by any device will not be allowed during meetings except by permission of the Chair.

10. Meeting Decorum and Rules of Debate

10.1. Robert's Rules of Order will govern the proceedings of Council and Committees of Council in all cases not provided for in this Policy or an Administrative Terms of Reference.

10.2. Members of the public present in the meeting room will maintain order and quiet and will not address the Council or Committee of Council except with permission of the Chair.

10.3. All cellular phones and electronic devices which emits a sound will be set to silent or turned off during a meeting, with the exception of equipment required for specific use related to the matter (i.e., issued tablets that would contain the agenda and related documents).

10.4. No one may bring any sign, poster, placard, banner or other like device into a meeting place without the prior permission of the Chair, subject to an objection by a majority of the members of Council or Committee of Council present

10.5. All Councillors, resident members, or other persons presenting to Council or a Committee of Council will not:

a) speak disrespectfully of any person;
b) use offensive language
c) speak on any subject other than the subject for which they received approval to speak;
d) disobey any decision of the Chair;
e) enter a cross debate with another member; or
f) willfully distract the member speaking, unless it is regarding a point of order or to raise a question of privilege.

10.6. A Council or a Committee of Council member or other persons may speak to a subject or motion at a meeting only if that member first addresses the Chair.

10.7. The Chair may ask questions and speak on a matter in the same manner as all Council or Committee of Council members without leaving the seat of the Chair.

10.8. Every Council or Committee of Council member or other person, prior to speaking on any question or motion, will signal their desire to speak by raising their hand or other acceptable manner and wait to be recognized by the Chair. When two or more members signal to speak, the Chair will designate who has the floor based on the opinion of the Chair as to who signaled first.

10.9. No Council or Committee of Council member or other person will speak more than twice (and the second time only to raise new information), for a maximum of five (5) minutes each time, without permission of Council on any motion except to explain misconception of his remarks. When a member wishes to explain a misconception, the member will signal to the Chair and ask permission of the Chair, without further comment, and if permitted by the Chair, will explain only an actual misunderstanding of language.

10.10. A Council or Committee of Council member may request the motion under consideration be read at any time during debate but may not interrupt while another member is speaking.

10.11. The mover of a motion will have the right to reply and sum up in closing the debate.

10.12. The Chair, after having called attention of Council or Committee of Council to the conduct of a member who persists in irrelevant or repetition of an argument during debate, may direct a member to discontinue speaking.

10.13. A Council or Committee of Council member, member of the public or other person willfully disregarding the meeting decorum or rules of debate or obstructing the business of the Council or Committee of Council meeting, may be ordered by majority vote of the members present, to leave the meeting, which for clarity means leaving the property of the meeting location.

10.14. Formal presentations will be made at any meeting of Council or Committee of Council meeting, with no individual presentation exceeding fifteen (15) minutes plus a period for questions. For purposes of efficiency and time management it will be the goal when setting an agenda to limit a maximum of two (2) formal presentations at any Committee of the Whole meeting, it will be at the discretion of Council to request presentations at Council meetings.

10.15. When a report, by-law, petition or other document is read or received, including those deemed received upon approval of the agenda, the Clerk or appropriate staff member will endorse upon it:

a) a note of the reading;
b) the date;
c) the way it was dealt with.

10.16. A meeting of Council or a Committee of Council will adjourn at 10:00 pm unless otherwise determined by a majority vote of the members present. If the meeting agenda is not completed as of 10:00 pm, the meeting will resume the next business day at 6:00 pm to complete the work from the previous day's approved agenda.

11. <u>Conflict of Interest</u>

11.1. In accordance with the Municipal Conflict of Interest Act each Councillor and resident member must self-identify and disclose any pecuniary interest in any item before Council, Committee of Council or external committee or board.

11.2. Where a Councillor or resident member, either on their own behalf or while acting for, by or with and/or through, another person has any pecuniary interest, direct or indirect on a subject they will:

a) prior to any consideration of the matter at the meeting, disclose the interest and the general nature there of;
b) leave their seat and sit in the gallery or exit the meeting room for the duration of the discussions pertaining to the matter;

c) not take part in the discussion of or vote on any question with respect to the matter;
d) not in any way before, during and/or after the meeting influence the voting on any question pertaining to the matter.

11.3. If the meeting is a closed meeting, in addition to complying with the requirements in Section 11.2, the Councillor or resident member will leave the meeting place for the part of the meeting during which the matter is under consideration.

11.4. Where the interest of a member has not been disclosed by reason of their absence from the particular meeting, the member will disclose the interest and otherwise comply at the next meeting they attend of Council, Committee of Council or external committee or board where the matter was discussed.

11.5. The Clerk or responsible staff member will record the name of the member, the meeting, the time they left their seat and returned, and the nature of the conflict of interest in the minutes of the meeting and a central registry of disclosure.

12. Motions and Voting

12.1. The types of motions which may be made at a Council or Committee of Council meeting are:
a) Main motions – reflects the proposed decision or action to be taken regarding a subject;
b) Subsidiary motions – facilitates or modifies the main motion;
c) Incidental motions – relates to a question of procedure regarding a main motion;
d) Privileged Motions – a motion which does not relate to the main motion but takes immediate priority.

12.2. The following are common but not all Subsidiary motions:
a) Postpone indefinitely – if approved this motion stops the main motion without a vote;
b) Amend – changes something within the main motion;
c) Postpone definitely – sets the main motion aside until a specified time;
d) Refer – sends the main motion to a specific committee or staff for further investigation and report back;
e) Limit or extend debate – shortens or lengthens the time for debate;
f) Previous Question – closes debate and brings the main motion to a vote;
g) Lay on the Table – puts the main motion aside temporarily for more urgent business and is taken up after the urgent business is dealt with.

12.3. The following are common but not all incidental motions:

a) Point of Order – asked the Chair to enforce the rules; more details in Section 13;
b) Appeal – takes the decision of the Chair away and gives it to members of Council or Committee of Council;
c) Suspend the rules – allow Council or Committee of Council to do something it normally cannot do without breaking the rules;
d) Objection to consideration of the question – avoids the main motion if Council or Committee of Council thinks the motion should never have been made or is outside the its mandate;
e) Division of a question – separate parts of a main motion into separate motions that can stand on their own for consideration.

12.4. The following are common but not all privilege motions:
a) Raising a question of privilege – is an emergency motion which deals with the rights and privileges of members;
b) Recess – provides a short break in the meeting;
c) Fix the time to adjourn – sets a time to adjourn the meeting;
d) Adjourn – closes the meeting.

12.5. All business before Council or Committee of Council for consideration will be made in the form of main motions which proposes specific action be taken.

12.6. All main motions will be provided to the Chair or Clerk in writing before being debated.

12.7. A motion must be seconded, and when requested read by the Chair or Clerk, before it is debated; except a motion raising a question of privilege or point of order.

12.8. Council or a Committee of Council may have informal discussions on a subject prior to making a main motion for consideration.

12.9. A motion may at any time after it is seconded and before the Council or Committee of Council has voted on it, be withdrawn or modified by the mover with consent of Council or Committee of Council.

12.10. When any main motion is being considered, the only motions in order will be:
a) to amend;
b) to refer;
c) to postpone either definitely or indefinitely; or
d) to limit or extend debate;
e) the previous question.

12.11. Amendments will be put in the reverse order of which they are made. Only one amendment will be allowed at a time and one sub-amendment will be allowed to an amendment. Every amendment submitted will be decided on or withdrawn before the main question is put to a vote.

12.12. A motion to adjourn will always be in order except in the following cases:
a) when a Council or Committee of Council member is in possession of the floor;
b) when the "yeas" and "nays" are being called;
c) while the Council or Committee of Council members are voting; or

d) when the motion to adjourn was the last preceding motion.

12.13. The following motions will be decided without debate:

a) a motion to reconsider;
b) all motions as to priority of business or as the suspension of the order of the day;
c) applications to speak more than the prescribed number of times;
d) a motion to allow any person other than a Council member to address the Council;
e) a motion to postpone definitely;
f) a motion to lay on the table when claiming a privilege over another person; and
g) a motion to adjourn.

12.14. Before putting the motion to a vote, the Chair will ask "Are you ready for the question" and if no member offers to speak on the motion or they make a motion for the Previous Question, the Chair will put the question, after which no member will be permitted to speak upon it.

12.15. The usual form of voting on any motion will be by the Chair calling for "yeas" and "nays", and members indicating their choice by show of hands or, if provided, by electronic means; but any Council or Committee of Council member, before or after the vote can call for, a recorded vote with each members vote entered into the minutes.

12.16. No motion committing the Municipality to the expenditure of funds will be accepted by the Chair for the consideration of Council, unless there is unanimous consent of Council members present, except for matters arising from correspondence, Committee of Council or other reports, agenda items, notices of motions or other material circulated to Council members on or before the day before the meeting, and except for matters arising from a closed meeting.

12.17. A majority vote of those present will determine all questions arising in Council and a Committee of Council, except motions to approve a planning document and those requiring a two-thirds (2/3) vote.

12.18. The adoption of planning documents or amendment thereof by Council at Second Reading requires a majority vote of number of Council members elected, regardless of number present to achieve quorum. And only those members present during a public hearing are permitted to vote on the matter at which a public hearing was held.

12.19. The following motions require a two-thirds vote:

a) to suspend the rules;
b) to limit or extend debate;
c) to amend or rescind something previously adopted;
d) to object to the consideration of the question; or
e) to close nominations.

12.20. Subject to the *Municipal Conflict of Interest Act*, all Council or Committee of Council members present including the Chair will vote on a motion and may not abstain.

12.21. A member of Council or Committee of Council who fails or refuses to vote on a motion is deemed to have voted in the positive.

12.22. In the event of a tie in a vote on a motion, the motion is determined in the negative.

12.23. Any notice of motion given by a Council or Committee of Council member for a subsequent meeting may, in the absence of the member giving such notice, be taken up by another member.

12.24. The following motions may bring a motion for consideration again:

a) Take from the table – takes up the motion previously laid on the table;

b) Rescind – takes back a motion or policy; for a by-law this is called a repeal, a notice to rescind must be given at a previous meeting;

c) Amend something previously adopted – modifies a motion previously presented and adopted;

d) Discharge a committee – takes a matter sent to a committee back before a report has been presented;

e) Reconsider – allows reconsideration due to new information or situation so the true will of the members is acted on.

12.25. No motion can be reconsidered if the actions cannot be undone.

12.26. After any main motion has been decided, any Council or Committee of Council member who voted on the winning side may, after the decision has been announced from the Chair, but before adjournment of the meeting may give notice of an intention to move reconsideration at the next meeting. The giving of such a notice operates as a stay or suspension of the decision.

12.27. In the event that Council or a Committee of Council member fails to give notice of reconsideration at the same meeting, the member will give notice in writing to the Clerk least 14 days prior to the next meeting but not thereafter, of Notice of Motion to reconsider the motion of a previous meeting, stating the reasons therefore, and if the motion for reconsideration is seconded, the same will be put to a vote after debate (unless it is an undebatable motion) and if carried, the question for reconsideration will then be read and disposed of.

12.28. No discussion of the main question will be allowed during the motion for reconsideration.

12.29. The following matters are not eligible for reconsideration:

a) a motion approving the first or second reading of a by-law enactment, amendment or repeal;

b) a motion to decide on a matter which was the subject of a statutory hearing by Council;

c) a motion which is or was considered by the Committee of the Whole or the Planning Advisory Committee in substantially the same form in which it is being or will be considered by Council, irrespective of whether Council has adopted or rejected or may adopt or reject, the recommendation;

d) a matter which has already been reconsidered once;

e) a vote to reconsider; and

f) a motion to reconsider or rescind a motion approving the annual budget of the Municipality or a motion authorizing any legal proceedings.

12.30. Any rule concerning motions and voting may be suspended for a specific matter with a motion, passed by two-thirds (2/3) vote of Council or Committee of Council members present, stating the specific rule to suspend and the matter for which it is suspended.

12.31. A summary of the rules for common motions can be found in Appendix B.

13. Points of Order (also refer to Code of Conduct Policy)

13.1. A point of order asks the Chair to rule on or enforce the rules if a Council or Committee of Council member thinks the rules of this Policy have been broken.

13.2. A point of order does not need to be seconded but must specify which rule is being broken and must be decided upon before the subject under consideration is proceeded with.

13.3. When a Council or Committee of Council member is called to order, the member will be seated and remain silent until the point is determined or until called upon by the Chair to be heard on the point of order.

13.4. A point of order is not debatable amongst other Council or Committee of Council members, unless the Chair invites discussion to assist in making a ruling. Where the Chair permits discussion on a point of order, no member will speak more than once.

13.5. Decisions of the Chair on points of order or procedure, including an order expelling and excluding a person from the meeting room pursuant to Sections 13.6 and 13.8, are not debatable but are appealable to Council or Committee of Council by any member. When an appeal is made of the decision of the Chair, the Chair will simply put the question, "Will the decision of the Chair be sustained?

13.6. If a Council or Committee of Council member resists:

a) the rules contained in this Policy;

b) willfully obstructs the business of Council or the Committee of Council;

c) disobeys the decision of the Chair, or of Council or Committee of Council on appeal, on any question of order or practice or upon the interpretation of the rules after being called to order by the Chair; or otherwise disrupts the meeting proceedings;

the member may be ordered by the Chair to leave their seat.

13.7. If the Council or Committee of Council member refuses to leave the Council members seat, the Chair may, after majority vote is made to support the expulsion, order the member to be expelled and removed from the meeting room.

13.8. Such Council or Committee of Council member may, by vote of the members, later in the meeting or at a subsequent meeting be permitted to re-enter the meeting room and to resume participation in Council or Committee of Council business with or without conditions.

13.9. Persons who are not Council or Committee of Council members, staff, or invited guests of the Municipality will observe silence and order in the meeting room, unless given permission to speak. Any such persons disturbing the proceedings of Council or Committee of Council will be called to order by the Chair and, if they fail to comply, will be expelled and excluded from the meeting room by the Chair, provided that a majority vote will be required to sustain the expulsion.

13.10. Such members of the public, by vote of the members, later in the meeting or at a subsequent meeting, may be permitted to re-enter the Council Chambers with or without conditions.

13.11. An order of the Chair to expel a person from the meeting room pursuant to Sections 13.6 and 13.8 of this Policy constitutes a direction from the Municipality to leave the premises for the purpose of the Protection of Property Act and other applicable laws.

14. <u>In-Camera Meetings</u>

14.1. Notwithstanding Section 3.1, Council or a Committee of Council may meet in-camera as per Section 22(2) of the Act, for the following reasons:

a) acquisitions, sale, lease and security of municipal property;
b) setting minimum price to be accepted by the municipality at a tax sale;
c) personnel matters;
d) labour relations;
e) contract negotiations;
f) litigation or potential litigation;
g) legal advice eligible for solicitor-client privilege;
h) public security.

14.2. No decision will be made while in-camera except decisions on matters of procedure or to give direction to the CAO or Solicitor. All other decisions will be made during a public meeting.

14.3. The meeting decorum and rules of debate of Section 10 apply during an in-camera meeting.

14.4. A record which is open to the public will be made, noting the fact that Council or Committee of Council had met in-camera, the type of matter as set out in Section 22(2) of the Act, and the date, but no other information.

14.5. Discussions held by those in attendance of an in-camera meeting are confidential unless required for Municipal, legal purposes pursuant to other regulatory requirements or released by motion of Council or the Committee of Council. These meetings will be recorded electronically for accuracy in the minute taking process, unless determined by Council to cease audio/video recording during the discussion.

14.6. An agenda and documentation for the in-camera meeting will be provided to Council or Committee of Council members only, in a manner similar to Section 7 of this Policy or may be handed out during the in-camera meeting. Such material will be deleted from the internal communication system or collected after the meeting.

14.7. Minutes of the in-camera meeting will be taken by the Clerk, or other responsible staff member, and approved at the next in-camera meeting of Council or Committee of Council.

Such minutes and meeting packages will be securely kept and will not be subject to mandatory public disclosure unless required for Municipal, legal purposes pursuant to other regulatory requirements, or released by motion of Council or the Committee of Council.

14.8. The Mayor, Deputy Mayor, Chair, Solicitor, CAO or designate, or Clerk will have authority to brief one another or any member of Council or Committee of Council who is absent from the closed session.

15. Setting Direction

15.1. To practice good governance and ensure that decisions are made in the best interest of the Municipality, businesses and residents; decisions should be assessed through the lenses of property, environment, economics, social and public opinion before recommending an action or making a decision. Appendix C has further details on the decision-making lenses.

15.2. Council may set direction and make decisions through resolutions, policies and by-laws. Committees of Council may make motions recommending a direction, policy, or by-law to Council.

15.3. The process to approve a resolution at a Council meeting does not require notice or public consultation. A motion becomes a resolution upon approval.

15.4. Approval of Policies:

a) The process for Council to approve a policy requires seven (7) days notice to all Council members but does not require public consultation. Notice may be given in one of the following manners:

i. Through a notice of motion regarding the policy at a Council meeting for approval at the next Council meeting, provided there are at least seven (7) days between meetings;

ii. Through a recommendation from Committee of the Whole to Council, provided there is at least seven (7) days between the meetings;

iii. Through a recommendation from Planning Advisory /Heritage Advisory Committee to Council, where such notice will be emailed to Councillors at least seven (7) days before the meeting.

15.5. Approval of By-laws and Planning Documents:

a) The process for Council to approve a by-law, other than a planning document, requires a First Reading at a Council meeting, a Public Hearing and a Second Reading at a subsequent Council meeting. A notice regarding the Public Hearing must be published in accordance with Section 168 (2) of the Act.

b) The process for Council to approve a planning document or amendment there of, after the requirements of the public participation program for planning documents have been met, requires a First Reading at a Council meeting, a Public Hearing and a Second Reading at a subsequent Council meeting. A notice regarding the Public Hearing must be published in accordance with Section 206 of the Act.

c) Council will receive no new information regarding the by-law or planning matter once a public hearing is complete.

d) Only the Council members present at the Public Hearing may vote on the Second Reading of the by-law and planning document.

15.6. Public Hearings are separate meetings which are held immediately before the Council meeting at which the Second Reading of the by-law or planning document is held. The agenda for the Public Hearing will be similar to the following:

a) Overview of by-law or planning document to be approved – by staff
b) Owner or Developer Presentations (if applicable)
c) Written Submissions in Favour or Against
d) Questions or Comments from the Public in Favour or Against
e) Concluding Remarks

15.7. Council may reverse a resolution or policy through a motion to rescind or repeal in the same manner it was created. The process to reverse a by-law is to create a new by-law stating the repeal.

15.8. The resolution, policy or by-law to be rescinded or repealed:

a) will have been approved at a previous Council meeting, and
b) will not have been carried out to the extend that it is too late to undo for the future.

16. <u>Receiving Public Input</u>

16.1. Council and Committees of Council members may obtain public input and opinions from residents in the following manner:

a) speaking with a resident directly;
b) at public consultation and information meetings;
c) during Public Hearings;
d) through formal presentation during meetings, requests which have been received by staff may be placed on the meeting agenda and approved by the Chair, prior to the meeting;
e) during the allotted twenty (20) minutes of Public Participation on all advisory committee agendas. A member of the public may speak for a maximum of five (5) minutes each during this period;
f) through formal petitions and written applications to Council, which are required to be signed.

16.2. Petitions and applications to Council will be:

a) legibly written or printed on paper;

b) will have endorsed upon it the name, address and signature of one or more petitioners, applicants or required persons, and the substance of the matter contained in it.
c) be presented by a Council member or staff member who will inform Council of the contents and ask permission of Council for it to be read on behalf of petitioners;
d) Council may decide to hear a summary of a petition or written application in lieu of hearing the reading of the entire petition or written application.

17. Committees

17.1. The Council of the Municipality may establish Committees of Council for various matters.

17.2. Committees of Council are advisory in purpose and may only make recommendations to Council for final approval and action, unless otherwise enabled under this Policy or by Provincial Legislation.

17.3. In addition to the Committee of the Whole, the following Committees of Council are here by established and details of the establishment can be found in the respective appendix to this Policy:

a) Accessibility Advisory Committee – Appendix D
b) Audit Committee – Appendix E
c) Repealed
d) Repealed
e) Fences Arbitration Committee – Appendix H
f) Repealed
g) Repealed
h) Mill Lakes Watershed Advisory Committee – Appendix J
i) Planning Advisory/Heritage Advisory Committee – Appendix K
j) Municipal Climate Change Action Plan Committee – Appendix L
k) Diverse and Inclusive Communities Committee – Appendix M
l) Police Advisory Board – Appendix N
m) Davidson Lake and French Mill Brook Watershed Advisory Committee – Appendix O

17.4. Council may also form Committees of Council as required under a by-law or agreement approved by Council.

17.5. Council may agree to participate in external boards and committees which are established by the Province, legal agreement or is of significant interest to the Municipality.

17.6. Council will not be bound by the by-laws or articles of incorporation adopted by an external committee or board providing for the appointment of a member to the committee or board.

17.7. Council agrees to participate in the following external boards and committees:

a) Annapolis Valley Regional Library Board
b) Hants County Residence for Senior Citizens Board
c) Cogmagun Landfill Community Liaison Committee
d) Region 6 Solid Waste Management Board
e) Valley Communication Fibre Network
f) Valley Regional Enterprise Network
g) Highway 101 Twinning Community Liaison Committee

17.8. Councillors are elected to various committees and boards every two (2) years, or as required by other legislation, policies or agreement, at the November Committee of the Whole meeting and ratified as a Special Council meeting immediately following to ensure there are no interruptions in the November committee meeting dates. The number of Councillors to be elected:

a) for Committees of Council one (1) or more Councillors may be elected in accordance with the Committee structure set by Council;
b) for external boards and committees, one (1) Councillor and one (1) alternate Councillor may be elected.

17.9. The election of Councillors to various committees and boards will be conducted in similar manner as the election of Deputy Mayor in Section 6.

17.10. Councillors not elected to a Committee of Council or external committee or board will not be permitted to participate in the committee debate or the vote; but are authorized to make comments, presentations, and participate in the committee meeting, to the extent authorized by the Chair.

17.11. A Councillor ceases to be a member of a Committee of Council or external committee or board when they cease to be a Councillor or as per poor conduct as per the Code of Conduct for Elected Officials Policy.

17.12. Council may appoint residents residing in the West Hants Regional Municipality (unless the committee's Terms of Reference state representation outside of the region is required)to serve on Committees of Council or to represent the Municipality on external board and committees.

17.13. All resident appointments will be advertised publicly with a request for those interested to submit a letter of interest and application for a committee. The letter of interest will be reviewed by the CAO or designate and staff who will then submit a recommendation to Council for appointment.

17.14. Committees of Council will be governed in accordance with this Policy, unless this Policy states that an alternate arrangement may be provided in the Administrative Terms of Reference of the Committee of Council.

17.15. Each member of a Committee of Council is to receive a copy of this Policy and the Committee of Council's Administrative Terms of Reference at the first duly called meeting of the Committee of Council after the regular election or appointment of members.

17.16. The Clerk will keep a record of all Councillor and resident appointments to Committees of Council and external committees and boards.

17.17. Councillors and resident members who sit on an external committee and board that has not been a result of an appointment by Council, will disclose the name of the external committee or board to the Clerk. The Clerk will keep a public record and will update the information in November of each year.

17.18. Council may by majority vote remove any Councillor or resident member of a Committee of Council or external committee or board who was elected or appointed by Council.

17.19. Council will fill any vacancy on a Committee of Council or external committee or board as soon as practicable after the vacancy occurs.

18. <u>Conferences and Training</u>

18.1. Up to six (6) Council members plus Mayor (and their spouses), and the CAO (or delegate) may attend the Spring conference held by the Nova Scotia Federation of Municipalities (NSFM). And, up to six (6) Council members plus Mayor (and their spouses), and the CAO (or delegate) may attend the Fall conference held by the NSFM; however, will be based on opportunity. The schedule of attendance will be revisited annually to promote fairness.

18.2. Annually, Council will approve participation in a conference held by the Federation of Canadian Municipalities (FCM), including the number of Council and staff members to participate through the provision of funding during budget deliberations.

18.3. Councillors may attend and be reimbursed for other related training opportunities with prior approval of Council.

18.4. Remuneration for conferences and training will be in accordance with the Remuneration Policy.

18.5. There will be an annual budgeted amount for Committees of Council members to attend conferences relevant to the committee in which they are appointed. This may include up to one resident member per Committee of Council.

18.6. The CAO will be responsible for promoting conference and professional development opportunities and for devising a system ensuring overall fairness for the opportunity to attend.

19. <u>Repeal</u>

19.1. The following policies of the former Municipality of the District of West Hants are hereby repealed effective April 1, 2020:

a) The Council Procedural Policy, COGE-003.00, dated February 14, 2017 as amended to September 10, 2019;

b) Audit Committee Policy, COFN-007.00, dated May 8, 2018;

c) Policy Establishing Davidson Lake Watershed Advisory Committee, COPW-003.00, dated December 8, 2015 as amended to June 12, 2018;
d) Establishment of the Falmouth Watershed Advisory Committee Policy COPW-002.00, dated February 13, 2018 as amended to June 12, 2018;
e) Policy to Establish the Fences Arbitration Committee, COGE-008.00, dated June 12, 2018;
f) Policy Establishing West Hants Planning Advisory Committee, COPL-006.00, dated December 11, 2018; and
g) Policy Establishing the Hantsport Area Advisory Committee, COPL-005.00.

19.2. The following policies of the former Town of Windsor are hereby repealed effective April 1, 2020:
a) Meeting Attendance via Video/Virtual Policy dated September 26, 2017;
b) Appointment of Deputy Mayor Policy dated November 25, 2014; and
c) Audit Committee Policy dated November 28, 2017.

19.3. The following polices of the West Hants Regional Municipality are hereby repealed effective December 10, 2024
a) Code of Conduct for elected Municipal Officials Policy RCOHR-002.00

20. <u>Related Legislation, Policies, Procedures</u>

20.1. The following is a list of related legislation, policies and procedures:
a) Municipal Government Act
b) Municipal Conflict of Interest Act
c) Freedom of Information and Protection of Privacy Act
d) Protection of Property Act
e) Robert's Rules of Order

APPENDIX A
Report Form

WEST HANTS REGIONAL MUNICIPALITY REPORT

Information ☐	Recommendation ☐	Decision Request ☐	Councillor Activity ☐

To: (Name of Committee)

Submitted by: ________________________________
(Name and Title)

Date: (Date)

Subject: (Title or Subject of Report)

LEGISLATIVE AUTHORITY

(State where ability for consideration comes from if applicable)

RECOMMENDATION or DECISION REQUEST

(State the recommendation or decision request in the form of a motion, if not applicable because it is an Information Report or Councillor Activity Report, state so)

BACKGROUND

Property☐	Public Opinion☐	Environment☐	Social☐	Economic☐	Councillor Activity ☐

(Provide the Who, What, When, Where and Why. If a Councillor Activity Report check “Councillor Activity” and provide your update/info below in the “Discussion” section.)

DISCUSSION

(Provide new information about the subject, Councillor activity, strategic implications, desired outcome.)

NEXT STEPS

(State what will be done next if anything.)

FINANCIAL IMPLICATIONS

(Inform of any financial implications it may have on current or future budgets of the Municipality, or to residents, if anything.)

ALTERNATIVES

(State any option to the recommendation and implication of the options, if anything)

ATTACHMENTS

(List any attachment to the report, if anything.)

CHIEF ADMINISTRATIVE OFFICER REVIEW

(For use if report is from a Councillor. CAO to provide additional comments on background, department/staff responsible and workload, budget, options, preferred strategy. State "Not Applicable" if report is from staff which already incorporates CAO review.)

Report Prepared by: ____
(Name and Title)

Report Reviewed by: ____
(Name and Title)

Report Approved by: ____
(Name and Title)

APPENDIX B

Rules of Common Motions

Privilege and Subsidiary motions are listed in the order of their precedence, with the highest ranking at the top. After the Chair states a motion, higher ranking motions are in order but not lower ranking motions, except to Amend and Previous Question can be applied to amendable and debateable motions of higher rank than themselves. Incidental Motions have no ranking order. These are the general rules relating to motions, special rules may apply in accordance with Roberts Rules of Order.

Type Of Motion	Motion in Order of Precedence	Seconded Needed?	Amendable?	Debatable?	Decided by?	Reconsider?	Interrupt?
Incidental Motions	Point of Order	No	No	No (unless Chair Permits)	Chair	No	Yes
	Appeal	Yes	No	Yes	Majority (Nays)	Yes	Yes (at time of ruling)
	Suspend the Rules	Yes	No	No	2/3	No	No
	Objection to the Consideration of the Question	No	No	No	2/3 (Nays)	Yes (Nays Only)	Yes (unless debate has begun)
	Division of the Question	Yes	Yes	No	Majority	No	No
Privilege Motions	Fixing the Time to Adjourn	Yes	Yes	No	Majority	Yes	No
	Adjourn	Yes	No	No	Majority	No	No
	Recess	Yes	Yes	No	Majority	No	No
	Raise a question of Privilege	No	No	No	Chair	No	Yes
Subsidiary Motion	Lay on the Table	Yes	No	No	Majority	No	No
	Previous Question	Yes	No	No	2/3	Yes	No

	Limit or Extend Debate	Yes	Yes	No	2/3	Yes	No
	Postpone to a Definite Time	Yes	Yes	Yes	Majority	Yes	No
	Refer	Yes	Yes	Yes	Majority	Yes	No
	Amend	Yes	Yes	Yes	Majority	Yes	No
	Postpone Indefinitely	Yes	No	Yes	Majority	Yes	No
Main	Original Motion	Yes	Yes	Yes	Majority	Yes	No

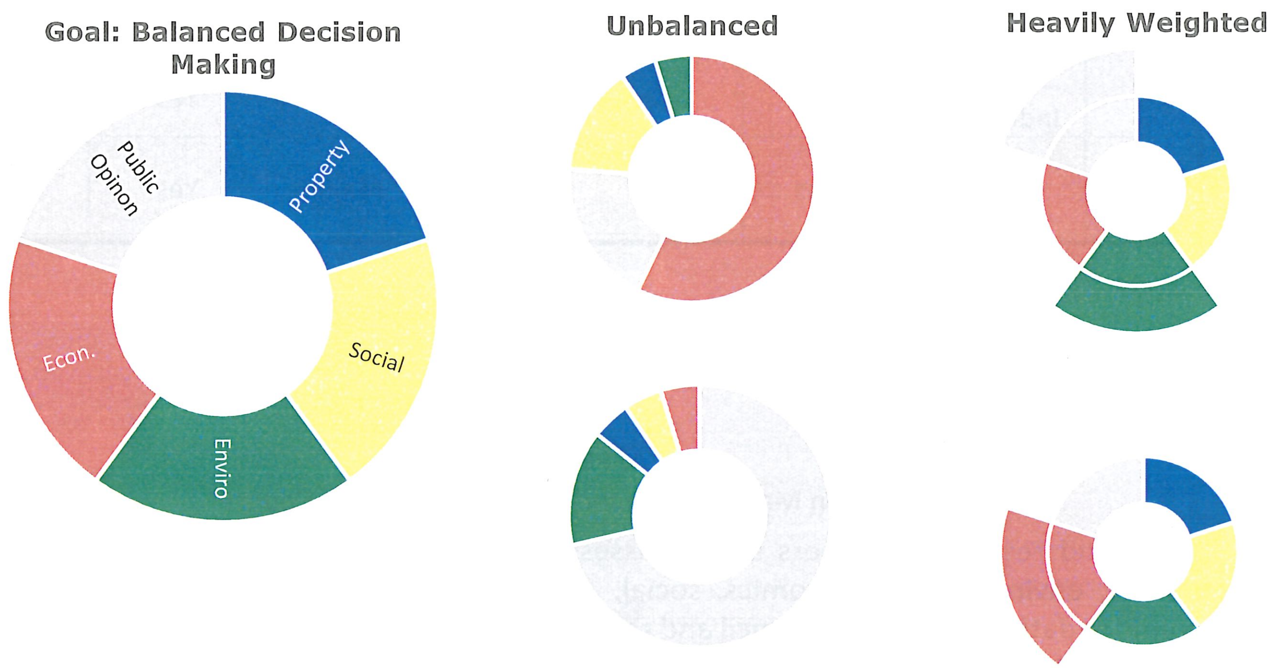
APPENDIX C

Decision Making by Council and Committee of Council

Council and resident members should assess every issue presented through the lenses of property, environment, economics, social, and public opinion before making a decision or recommendation for action. Council and residents have the responsibility to research all lenses in order to make a balanced and respectful decision. Information on an issue can become heavily weighted around a single lens, leaving out other factors that will influence the community as a whole. Council and resident members strive to make recommendations that are balanced and unbiased, without emotion, which reflect all lenses, to protect the best interests of the Municipality and the people it serves.

- **Property:** "something at the disposal of a person, a group of persons, or the community or public”. Examples: single use, shared use, noise, beautification, traffic, zoning, regulations
- **Environment:** "the air, water, minerals, organisms, and all other external factors surrounding and affecting a given organism at any time”. Examples include regulatory requirements and land use.
- **Economic:** "pertaining to the production, distribution, and use of income, wealth, and commodities". Examples: cost savings or expense with decision, property taxation, spending in community, tourism, assessments, market impacts
- **Social:** "of or relating to human society". Examples: Acceptance, limited available or benefit, values

- **Public Opinion:** "the collective opinion of many people on some issue, problem, etc., especially as a guide to action, decision, or the like". Examples: feedback, communication, media, other municipal units
- **Other:** In some cases, other lenses may be required to fully understand an issue. Examples: chance of success, innovation.



APPENDIX D

Accessibility Advisory Committee

1. PURPOSE

   1.1. The Accessibility Advisory Committee provides advice to Council on identifying, preventing and eliminating barriers to people with disabilities in municipal programs, services, initiatives and facilities. The Committee plays a pivotal role in helping the West Hants Regional Municipality become a barrier-free community and ensuring obligations under "An Act Respecting Accessibility in Nova Scotia (2017)" are met.

2. SCOPE

2.1. This Policy is applicable to all members appointed to the Municipality's Accessibility Advisory Committee.

3. DEFINITIONS

3.1. In Appendix D,

a) "AAC" means the Accessibility Advisory Committee of the Municipality;

b) "Act" means the *Accessibility Act*;

c) "Barrier" means anything that hinders or challenges the full and effective participation in society of persons with disabilities including a physical barrier, an architectural barrier, an information or communication barrier, an attitudinal barrier, a technological barrier, a policy or a practice;

d) "Council" means the Council for the Municipality;

e) "Disability" includes a physical, mental, intellectual, learning or sensory impairment, including an episodic disability; that, in interaction with a barrier, hinders an individual's full and effective participation in society;

f) "Municipality" means the West Hants Regional Municipality.

4. COMMITTEE COMPOSITION

4.1. The AAC will consist of no less than seven (7) members as follows:

- To a two-year term – One (1) members of Council and One (1) Alternate
- To a two-year term – No less than Four (4) Resident members
- To a three-year term – No less than Two (2) Resident members.

4.2. Resident members will not be members of Council or employees of the Municipality.

4.3. At least one half of the members of the AAC must be persons with disabilities or representatives from organizations representing persons with disabilities.

4.4. If a member vacates AAC for any reason at any time before that member's term would normally expire, Council will promptly appoint a new member to the Committee to hold office for the unexpired term.

4.5. The Chair and Vice-Chair will be appointed annually by the members of AAC.

5. MANDATE AND RESPONSIBILITIES

5.1. AAC has the following responsibilities:

a) Advise Council in the preparation, implementation and effectiveness of its accessibility plan. In accordance with the Act, the plan must include:

- A report on measures the Municipality has taken and intends to take to identify, remove and prevent barriers;

- Information on procedures the Municipality has in place to assess the following for their effect on accessibility for persons with disabilities:
  i. Any of its proposed policies, programs, practices and services, and
  ii. Any proposed enactments or bylaws it will be administering; and
    - Any other prescribed information.

b) Advise Council on the impact of the Municipality's policies, programs and services on persons with disabilities;

c) Review and monitor existing and proposed Municipal by-laws to promote full participation of persons with disabilities, in accordance with the Act;

d) Identify and advise on the accessibility of existing and proposed municipal services and facilities;

e) Advise and make recommendations about strategies designed to achieve the objectives of the Municipality's Accessibility Plan;

f) Receive and review information directed to it by Council and its committees, and to make recommendations as requested;

g) Monitor Federal and Provincial government directives and regulations; and,

h) Host community consultations related to accessibility in the Municipality.

6. ADMINISTRATION

6.1. AAC will meet no less than six times per year, or otherwise as required to fulfill the duties as outlined.

6.2. A quorum for AAC will be a majority, four (4) members.

6.3. The AAC may receive presentations from the public upon approval of the Chair.

6.4. The AAC may establish Working Groups to explore specific issues related to the accessibility plan and/or to other responsibilities. Members of the Working Group may consist of additional members of the community. A member of the AAC shall chair the Working Group.

APPENDIX E

Audit Committee

1. PURPOSE

1.1. The primary purpose of the Audit Committee (the "Committee") is to provide advice to Council on all matters relating to audit and finance. The objective of the Committee is to:

a) fulfil the requirements outlined in Section 44 of the *Municipal Government Act*; and

b) assist Council in meeting its oversight responsibilities by ensuring the adequacy and effectiveness of financial report, risk management and internal controls.

2. SCOPE

2.1. This Policy is applicable to all serving members Audit Committee.

3. DEFINITIONS

3.1. In Appendix E,

a) "Auditor" means the External Auditor conducting the audit of the Municipality;
b) "CAO" means the Chief Administrative Officer for the Municipality;
c) "Director of Finance" means the Director of Financial Services for the Municipality;
d) "Municipality" means the West Hants Regional Municipality.

4. COMMITTEE COMPOSITION

4.1. Council will annually appoint members to an Audit Committee.

4.2. The Audit Committee will consist of five (5) members: the Mayor, two Council members, and two resident members who are not members of Council or Municipal Staff.

a) Resident members should be sufficiently versed in financial matters to understand the Municipality's account practices and policies and the major judgements involved in preparing the financial statements.
b) Where an audit committee does not include any resident members, the audit committee will continue to meet and perform its duties and may exercise its powers. The Municipality will advertise to recruit resident members at least once every six months until the requirement is met.
c) The Mayor will chair the Audit Committee meetings, and in their absence, another appointed Council member will chair.
d) The CAO and/or Director of Financial Services will provide staff support to the Committee. They are not voting members of the Committee.
e) The Council Renumeration Policy will be followed regarding any remuneration for the two resident members.
f) All members must abide by the Administrative Terms of Reference set out by the Committee and reviewed the by CAO.

5. DUTIES AND RESPONSIBILITIES

5.1. Audit:

a) Review the qualifications, independence, quality of service, performance, and fees of the auditors and recommend the appointment of an auditor to Council.
b) Carry out the responsibilities of the Audit Committee contained in Section 44 of the *Municipal Government Act*, in consultation with Management.

5.2. Finance and Risk Management

a) Review with Management the quarterly financial updates and recommend to Council to be received.

b) Management will give a presentation on all financial policies used in the preparation of the external financial statements; at the first annually meeting of the year.

c) Review with Management the adequacy of internal controls.

d) Review with Management annually risk management practices including insurance coverage.

6. ADMINISTRATION

6.1. Meetings of the Audit Committee will be held at least quarterly. Additional meetings may be necessary to review items relating to the audit and will be called by the Chair.

APPENDIX F

Repealed

APPENDIX G

Repealed

APPENDIX H

Fences Arbitration Committee

1. PURPOSE

1.1. The purpose is to establish the Fences Arbitration Committee in accordance with the Fences and Detention of Stray Livestock Act.

2. DEFINITIONS

2.1. In Appendix H,

a) "Act" means the Fences and Detention of Stray Livestock Act, as amended from time to time;

b) "Clerk" means the Municipal Clerk of the Municipality;

c) "Committee" means the Fences Arbitration Committee of the Municipality;

d) "Council" means the Council of the Municipality;

e) "Livestock" means cattle, sheep, swine, goats, horses, ponies, mules, ratites, farmed deer and game farm animals and other livestock designated by the Minister;

f) "Minister" means the Minister of Agriculture;

g) "Municipality" means the West Hants Regional Municipality;

h) "Non-livestock farm" means land upon which no livestock is maintained.

i) "Owner" includes

i. With respect to livestock, any person who has lawful custody of the livestock

ii. With respect to a farm, the person occupying or operating a farm.

3. <u>FORMATION OF THE FENCES ARBITRATION COMMITTEE</u>

3.1. The Committee will consist of two (2) members, of which one member is appointed by Council and one member of the Municipality appointed by the Nova Scotia Federation of Agriculture.

3.2. The member appointed by Council will be the Chair of the Committee and may be an employee of the Municipality.

3.3. Alternate members of the Committee may be appointed at the request of the member appointed by the Municipality or the Nova Scotia Federation of Agriculture.

3.4. All members or alternates will be residents of the Municipality.

3.5. Non-Council members will be paid remuneration in accordance with the Council Remuneration Policy.

3.6. The Committee will meet on an as needed basis.

3.7. Two (2) members of the Committee will form a quorum.

3.8. All members must abide by the Administrative Terms of Reference, set out by the Committee and reviewed the by Chief Administrative Officer.

4. <u>DUTIES</u>

4.1. The Committee will perform the duties as required by and in accordance with the Act, which include but not limited to:

a) Hearing fencing disputes between the owners of a livestock farm(s) or between the owner of a livestock farm and a non-livestock farm; who have notified the Clerk in writing and paid the accompanied fee. With respect to the matter referred to the Committee, the Committee may, by written order,

i. Determine the location, height and material of construction of any fence;
ii. Determine the manner of maintenance of a fence;
iii. Direct the owner of a farm to construct or maintain any fence in accordance with the Act;
iv. Determine the proportion of costs of building and maintaining any fences and common boundaries to be borne by each of the adjoining livestock farm owners pursuant to the Act;
v. Take any immediate action necessary including, but not limited to, the removal and boarding of livestock if it is determined there is a risk to the public, the livestock or property.

b) Directing a sale or other disposition of stray livestock, provided subsections (2), (3), and (4) of Section 9 of the Act have been complied with.
c) Disposing of stray livestock in such as manner as it deems fit, should no offer or reasonable offer be made at sale.
d) Distributing the proceeds of the sale or disposal of stray livestock in accordance with the Act.
e) Settling disputes regarding ownership and expenses of stray livestock that arise between the owner of the livestock, the person detaining it or the Municipality.

5. <u>CONFLICT</u>

5.1. Where there is a conflict between this Policy and the Act, the Act will prevail.

APPENDIX I

Repealed

APPENDIX J

Mill Lakes Watershed Advisory Committee

1. <u>PREAMBLE</u>

1.1. The Mill Lakes Watershed supplies the reservoir from which the Windsor Water Utility, operated by the Municipality, withdraws water. The Windsor Water Utility currently supplies water to the community of Windsor and the Three Mill Plains Water Utility. The Three Mile Plains Water Utility services communities of Three Mile Plains, Currys Corner, Garlands Crossing, and Wentworth Creek.

In 1964, the area surrounding Mill Lakes, Hants County, was designated a Protected Water Area. Regulations were also enacted for the designated area to protect the water supply. The regulations were updated in 1986 under the Water Act. The Mill Lakes Watershed Protected Water Area contains four thousand three hundred ninety-four and a half (4394.5) acres of land (1778.4ha).

The Mill Lakes Watershed Committee was first established in 2005 by the former Town of Windsor in response to the need to develop a Source Water Protection Plan.

2. <u>DEFINITIONS</u>

2.1. In Appendix J,

a) "Committee" means the Mills Lakes Watershed Advisory Committee;
b) "Councillor" means an elected member the Council of the Municipality;
c) "Municipality" means the West Hants Regional Municipality;
d) "Staff" means a person employed by the Municipality.

3. <u>PURPOSE</u>

3.1. The primary objective of the Mill Lakes Watershed Advisory Committee is to provide a forum for the Landowners, the Municipality and other Stakeholders to work cooperatively to maintain the water quality and quantity in the Mill Lakes Watershed. The Committee recognizes that the protection of source water is the first step in the multi-barrier approach to clean, safe drinking water.

4. <u>ROLE OF THE MILL LAKES WATERSHED ADVISORY COMMITTEE</u>

4.1. The Committee advises the Municipality and Director of Public Works on issues pertaining to the Mill Lakes Watershed.

4.2. In addition, the Committee will:

a) assist in the development and implementation of a Source Water Protection Plan, which will be reviewed periodically;
b) assist with revisions of the regulations for the Protected Water Area as required;
c) review the details of the establishment of the Committee and make recommendation of changes to the Council of the Municipality on as need basis;
d) provide a forum for the involvement of landowners and exchange of information in matters regarding the watershed and water resources;
e) provide a forum to deal with issues and concerns in the watershed and address problems and solutions on matters of concern, as they arise;

f) advise on forest matters and other land use issues;
g) develop Best Management Practices (BMP) for activities in the Mill Lakes Watershed. These Best Management Practices will also be used to guide any approval processes for activities;
h) review and make recommendations on activities affecting the Protected Water Area, as requested by the Municipality;
i) provide and develop information and education about the Protected Water Area for residents, landowners, and users of the Mill Lakes Watershed;
j) liaise with government agencies and other resources not represented on the committee on matters affecting the Protected Water Area, such as the Provincial Department of Agriculture and Fisheries (DAF) and the Federal Department of Fisheries and Oceans (DFO).
k) provide information on the Committee's activities to landowners in the Protected Water Area.

5. COMMITTEE COMPOSITION

5.1. The Committee members will be comprised of:
- Four (4) Landowner Representatives
- One (1) Councillor and one (1) alternate
- One (1) Nova Scotia Department of Lands and Forestry Representative
- One (1) Water Utility Representative
- One (1) Planning and Development Department Representative
- One (1) Nova Scotia Environment Representative (voting)

5.2. The Landowner Representatives must own land in the Mill Lakes Watershed and will not include the Municipality.

6. ADMINISTRATION

6.1. A quorum for the Committee will be five (5) members; of which two (2) must be a Landowner Representatives and one (1) must be a Councillor.

6.2. The Chair of the Committee will be elected by and from the Committee. The Chair will be responsible for reporting the activities of the Committee to the Committee of the Whole. The Committee Chair will be elected every two years on even numbered years by the Committee.

6.3. The Committee will meet semi-annually. The Chair may call for additional meetings as required.

6.4. All Landowners are welcome to attend Committee meetings as observers.

6.5. A General Meeting of landowners may be called every two (2) years at the discretion of the Committee.

6.6. Administrative services for the Committee will be provided by the Municipality.

6.7. All members must abide by the Administrative Terms of Reference set out by the Committee and reviewed the by Chief Administrative Officer.

APPENDIX K

Planning Advisory/Heritage Advisory Committee

1. PURPOSE

1.1. To establish an advisory committee in accordance with Sections 200 and 202 of the Municipal Government Act.

The Planning Advisory/Heritage Advisory Committee will advise the Council of the Municipality on planning and heritage matters requiring a decision of Council affecting the Municipality, including the preparation and amendment of planning documents.

2. DEFINITIONS

2.1. In Appendix K,

a) Repealed.

b) "Municipality" means the West Hants Regional Municipality;

c) "PAC/HAC" means the Planning Advisory/Heritage Advisory Committee of the Municipality;

d) Repealed.

3. COMMITTEE COMPOSITION

3.1. The PAC/HAC will be established under the following terms:

a) The Committee will consist of ten (10) members as follows: three (3) resident members from the former Municipality of West Hants area (excluding Hantsport) who are not Council members or Municipal Employees, two (2) resident members from the community of Hantsport who are not Council members or Municipal Employees, two (2) resident members from the community of Windsor who are not Council members or Municipal Employees and three (3) members of Council.

4. ADMINISTRATION

4.1. The PAC/HAC will appoint a Chair and Vice-Chair annually from among its members at the November meeting.

4.2. All non-Council members of the Committee will be remunerated for attendance at meetings of the Committee in accordance with the Remuneration Policy.

4.3. The PAC/HAC will present recommendations directly to the Council of the Municipality.

4.4. Resident Committee Members may be reappointed for a maximum of three (3) terms.

APPENDIX L
Climate Action Committee

1. PURPOSE

1.1. The Climate Action Committee provides a forum for all municipal departments and Council representatives to work co-operatively on implementing and evaluating the adaptation and mitigation actions outlined in the Climate Change Action Plans of the Municipality hereafter referred to as "the CAC". These policy and adaptation procedures help protect people, properties, special places, and municipal infrastructure from the negative impact of climate change.

2. DEFINITIONS

2.1. In Appendix L,

a) "CAC Committee" means the Climate Action Plan Committee;
b) "Municipality" means the West Hants Regional Municipality.

3. COMMITTEE COMPOSITION

3.1. The Committee consists of eleven (11) members:

- Three (3) Councillors;
- Two (2) resident members, who are not members of Council
- Chief Administrative Officer or designate;
- Director of Public Works or designate;
- Director of Planning and Development or designate;
- Director of Community Development or designate;
- Director of Financial Services;
- Protective Services Manager or designate.

3.2. Each Councillor, appointed by Council, serves on the Committee for a designated term. Members are eligible for reappointment.

3.3. Designates and alternates are at the discretion of the Chief Administrative Officer.

4. ADMINISTRATION

4.1. The Chair and the Vice-Chair are elected by a majority of the members. Those persons elected hold office for a one-year term.

4.2. The Chair of the Committee acts as the liaison in providing recommendations to Council, as required from time to time.

4.3. The duties and procedures of the CAC Committee will be as set out in the relevant Terms of Reference for the CAC Committee as approved by motion of the Committee and reviewed by the Chief Administrative Officer.

APPENDIX M

Diversity and Inclusive Communities Committee

1. MANDATE

1.1 Through the establishment of this committee, we are committed to strengthening existing partnerships while collaborating with individuals, groups, and organizations to reduce systemic racism and discrimination while strengthening the ability of individuals and community to address issues of diversity, justice, and inequality while providing opportunities for inclusiveness and belonging to improve the lives of all.

2. PURPOSE

2.1 The purpose of the Diverse and Inclusive Communities Committee is to serve in an advisory capacity and make recommendations to Council which will formulate strategic action plans achieve the following:

a) Advocate, educate, celebrate, address, and advise on issues concerning social marginalization, equity, racism, and discrimination within the Municipality and its workplaces.

b) Break down barriers and implement programs, policies, and practices that promote diversity and inclusion and create opportunities which are inclusive and welcoming to all.

3. DEFINITIONS

3.1. In Appendix M

a) "Municipality" means the West Hants Regional Municipality

4. COMPOSITION

4.1 The Committee will consist of eight (8) voting members to ensure all perspectives are represented and side in a tie breaking scenario that promotes progression without uncertainty and ten (10) non-voting supporting members as follows: Eight (8) citizen members of diverse race and ethnicity (including, but not limited to those from the

African Descent, Acadian, Glooscap First Nation, Indigenous, 2LGBTQIA+, Senior, Youth, and Newcomers' communities) (voting)

- One (1) Supporting and Promoting Equality in our Communities (SPEC) Community Group Representative (non-voting)
- One (1) RCMP Representative (non-voting)
- One (1) Community Health Board Representative (non-voting)
- Six (6) non-voting staff members appointed by the Chief Administrative Officer (non-voting)
- One (1) Councillor and one (1) Alternate (non-voting)

5. ADMINISTRATION

5.1. A Chair and Vice-Chair will be elected bi-annually based upon the date of the Committee establishment.

5.2. Citizen committee members will serve a two (2) year term.

5.3. Citizen committee members may be reappointed for a maximum of three (3) terms.

5.4. Citizen Committee members will be provided remuneration in accordance with the Council Remuneration Policy.

5.5. Administrative services for the Committee will be provided by the Municipality.

5.6. All members must abide by the Administrative Terms of Reference set out by the Committee and reviewed the by Chief Administrative Officer.

APPENDIX N

Police Advisory Board Committee

1. PURPOSE

1.1 The purpose of the Police Advisory Board Committee is to provide advice to Council in relation to the enforcement of law, the maintenance of law and order and the prevention of crime in the Municipality. The Advisory Board does not, however, exercise jurisdiction relating to the complaints, discipline, personnel conduct or the internal management of the Royal Canadian Mounted Police.

2. DEFINITIONS

2.1. In Appendix N

a) "Municipality" means the West Hants Regional Municipality

b) "PAB" means the Police Advisory Board

3. COMPOSITION

3.1 The Police Act of NS – Section 57 - Establishment and composition of Police Advisory Boards, and Section 68(1) – Function of Advisory Board

The Committee will consist of five members:
(a) two members of council appointed by resolution of the council;
(b) two members appointed by resolution of the council, who are neither members of council nor employees of the municipality; and
(c) one member appointed by the Minister.

4. ADMINISTRATION

4.1. Each Councillor, appointed by Council, serves on the Committee for a designated term (2 years). Members are eligible for reappointment.

4.2. A Chair will be elected bi-annually, with the next appointment commencing November 2024.

4.3. Citizen and Council committee members will serve a two (2) year term.

4.4. Citizen Committee members will be provided remuneration in accordance with the Council Remuneration Policy.

4.5. Administrative services for the Committee will be provided by the Municipality.

4.6. All members must abide by the Administrative Terms of Reference set out by the Committee and reviewed the by Chief Administrative Officer.

4.7. Meetings will be held at least quarterly.

APPENDIX 0

Davidson Lake & French Mill Brook Watershed Committee

1. OFFICIAL NAME

Davidson Lake & French Mill Brook Watershed Committee

2. MEMBERS/COMPOSITION

Four (4) Landowner Representatives
One (1) Councillor and (1) alternate
One (1) Nova Scotia Department of Natural Resources
One (1) Water Utility Representative
One (1) West Hants Regional Municipality Planning Department
One (1) Nova Scotia Environment Representative (voting)
One (1) NSTIR Representative (non-voting)

LANDOWNERS

The landowners are responsible for having representation on the Watershed Committee. They are in a unique position of knowing the watershed and their land, in addition to their own and their neighbours' land use practices. The landowners are encouraged to: Express their concerns and interests: advise and provide information to the Committee on land use management and source water protection; communicate with other landowners on Committee activities; and report any problems that they may encounter within the watershed.

WEST HANTS REGIONAL MUNICIPALITY COUNCILLORS

It is the responsibility of the West Hants Councillors to represent the interests of the citizens served by the Falmouth (West Hants) Water Utility. The Councillors will also represent the landowner's interests within the watershed.

DEPARTMENT OF LANDS AND FORESTRY (DLF)

The DLF representative will work with the Committee providing information and advising on topics related to forestry, wildlife, and source water protection. The representative will also represent the Department's interests as a landowner in the watershed.

STAFF (WATER WORKS OPERATOR, WEST HANTS PLANNING DEPARTMENT)

Staff will report to the Committee on activities undertaken by the West Hants Regional Municipality and any approvals in the Protected Water Area. Staff will work with the Committee providing information and advising on topics relating to source water protection, watershed management, land use and the operation of the Falmouth (West Hants) Water Utility. Staff will also bring forth concerns relating to water quality and watershed management.

NOVA SCOTIA ENVIRONMENT (NSE)

The NSE representative will work with the committee providing information and advising on topics related to source water protection, watershed management, the Environment Act and Protected Water Area Regulations.

NOVA SCOTIA DEPARTMENT OF TRANSPORTATION AND INFRASTRUCTURE RENEWAL (NSTIR)

The NSTIR representative will work with the Committee to provide information and advise on topics related to roads, bridges, and transportation.

TERM OF MEMBERSHIP

All non appointed members (landowners) will serve for a two-year term (except for the first term whereby half of the members shall serve for a three-year term to ensure continuity of membership). Subsequent appointments or re-appointments of landowners to the Committee shall be for a term of two years. Should there be several interested volunteers an election will be held amongst landowners to determine landowner membership.

3. GOALS

The primary goal of the Davidson Lake & French Mill Brook Watershed Advisory Committee is to provide a forum for the Landowners, the West Hants Municipality Water Utility, and other Stakeholders to work cooperatively to maintain the water quality and quantity in the Davidson Lake & French Mill Brook Watershed. The Committee recognizes that the protection of source water is the first step in the multi-barrier approach to clean, safe drinking water.

4. DELIVERABLES

The Davidson Lake & French Mill Brook Watershed Advisory Committee advises the West Hants Regional Municipality Council and Director of Public Works on issues pertaining to the French Mill Brook Watershed. In addition, the Watershed Advisory Committee shall:

- Assist in the development and implementation of a Source Water Protection Plan, which will be reviewed periodically.
- Assist with revisions of the regulations for the Protected Water Area as required.
- Amend these Terms of Reference for the Davidson Lake & French Mill Brook Watershed Advisory Committee as needed.
- Provide a forum for the involvement of landowners and exchange of information in matters regarding the watershed and water resources.
- Provide a forum to deal with issues and concerns in the watershed. The Committee will address problems and solutions on matters of concern, as they arise.
- Advise on forest matters and other land use issues.
- Develop Best Management Practices for activities in the watershed. These Best Management Practices will also be used to guide any approval processes for activities.
- Review and make recommendations on activities affecting the Protected Water Area, as requested by the West Hants Regional Municipality.
- Provide and develop information and education about the Protected Water Area for
- residents, landowners, and users of the watershed.
- Liaise with government agencies and other resources not represented on the committee on matters affecting the Protected Water Area, such as the provincial Department of Agriculture and Fisheries (DAF) and the federal Department of Fisheries and Oceans (DFO).
- To provide information on Committee activities to landowners in the Protected Water Area.

5. JURISDICTION

The West Hants Regional Water Utility, which is a combined utility with the former Hantsport, Falmouth and Three Mile Plains Water Utilities is operated by the West Hants Regional Municipality and supplies potable water to the areas of the communities of Hantsport, Hants Border and Glooscap First Nations Source water for the utility is withdrawn from the Davidson Lake, which is supplied by a near by spring. The Community of Falmouth Source water for the utility is withdrawn from the French Mill Brook Reservoir, which is supplied by the French Mill Brook and its watershed.

In 2017, the area surrounding Davidson Lake, West Hants, was designated as a Protected Water Area at the request of the former Municipality of the District of West Hants. Regulations were also enacted for the designated area to protect the water supply. The former Municipality along with NSE had been working together on this process for several years prior to the official designation. The Davidson Lake Watershed Protected Water Area covers approximately three hundred and twenty-nine (329) acres of land (133ha). The Davidson Lake Watershed Advisory Committee was established in January 2006 to manage the Davidson Lake Watershed through the involvement of stakeholders, including landowners, municipal staff, and government representatives. In 1983, the area surrounding French Mill Brook, West Hants, was designated as a Protected Water Area at the request of the Municipality of West Hants. Regulations were also enacted for the designated area to protect the water supply. The Municipality along with NSE had been working together on this process for several years prior to the official designation. The regulations were updated in 2004 and again in 2007, due to the requirements under the environment act. The French Mill Brook Watershed Protected Water Area covers approximately two thousand eight hundred and fourteen (2814) acres of land (1139ha), according to the plan prepared in 1974. The Falmouth Watershed Committee was established in 1992 to manage the French Mill Brook Watershed through the involvement of stakeholders, including landowners, municipal staff, and government representatives.

6. GOVERNANCE

The role of this committee is an advisory role to council. All approved motions within the Committee pertaining to the direct affect of the Davidson Lake & French Mill Brook Watershed and/or the Source Water Protection Plan shall be submitted to Council for final approval.

MEETING DETAILS:

- Meeting Quorum: Five (5) Committee Members, of which a minimum must be two (2) private landowners and one (1) councillor.
- Motions must be approved by 50% plus 1 to be carried.
- Chair: The Committee Chair will be elected biannually on even numbered years by the Committee.
- All Landowners are welcome to attend Watershed Advisory Committee meetings as observers.
- An Annual General Meeting may be called at the discretion of the Committee.
- Secretarial Services will be provided by the Municipality of West Hants.
- Meetings shall be held biannually April & October.

7. COMMUNICATIONS

A contact list will be circulated to the committee members and updated as required. Meeting invites and packages will be circulated via an email list a minimum of one week prior to each meeting.

7. RELATED POLICIES, PROCEDURES AND LEGISLATION

RCOGE-003.00 Meeting and Committee Procedural Policy

I, Deanna Snair, Municipal Clerk of the West Hants Regional Municipality, the Province of Nova Scotia, do hereby certify that this is a true copy of the policy as adopted by the Council of the West Hants Regional Municipality at a meeting duly called and held on the **25th** day of **February 2025.**

Deanna Snair
Deanna Snair
Municipal Clerk

Adoption	
Notice to Council:	March 9, 2020
Approval:	March 23, 2020
Description: Initial approval of the Meeting and Committee Procedural Policy, RCOGE-003.00. Approved by the Co-ordinating Committee of the Region of Windsor and West Hants Municipality.	
First Amendment	
Notice to Council:	October 13, 2020
Approval:	October 27, 2020
Description: Amended Policy to add the Diversity and Inclusion Committee, changed the report form, terminology changes and amend agenda package procedures.	
Second Amendment	
Notice to Council:	February 9, 2021

Approval:	February 23, 2021
Description: Amended Policy to delete the words "and December" from Sections 3.2(b) and 3.3 (b), to enable meetings in December.	
Third Amendment	
Notice to Council:	March 9, 2021
Approval:	March 23, 2021
Description: Amended Policy to remove the Hantsport and Windsor Area Advisory Committee, change the membership of Planning Advisory / Heritage Advisory Committee, and change the definition of "Municipality" within the Appendices.	

Fourth Amendment	
Notice to Council:	April 12, 2022
Approval:	April 26, 2022
Description: Amend Policy (Section 9.3) to add that In-Camera meeting sessions be recorded to ensure accuracy which results in all meetings are recorded.	
Fifth Amendment	
Notice to Council:	*June 14, 2022*
Approval:	*June 28, 2022*
Description: • Amend Appendix K, Section 3.1 to read that the committee will consist of ten (10) members as follows: seven (7) resident members from the region of West Hants who are not council members or municipal employees or immediate family members (defined as children, brother, sister, spouse, mother, father) of either Council or municipal employees and three (3) members of Council and further that this will take effect at the November PAC/HAC meeting. • Amend Appendix K to remove section 3.1 B that reads "council members will be appointed to the committee in November for a term of one (1) year and the term will expire following the October meeting the next year. the appointments made as of April 2021 will expire October 2022", as per section 17.8 it automatically makes it a 2 yr. term. • Amend Appendix K to add a Section 4.1 to read resident members may be reappointed for a maximum of three (3) terms. • Amend Appendix M to reflect the changes noted in Attachment B; and further direct staff to advertise for interested parties who will become the voice and support of the diverse and inclusive communities committee.	

• Amend Section 8.1 to read "the chair of council will be the Mayor and the Chair of Committee of the Whole will be the Deputy Mayor except: a) in the absence of the Mayor at Council, the Deputy Mayor will be the Chair and b) in the temporary absence of both the Mayor and Deputy Mayor, a Chair will be appointed from the Councillors present at the meeting.	
Sixth Amendment	
Notice to Council:	*July 12, 2022*
Approval:	*July 26, 2022*
Description: • Amend the Policy to make the necessary changes to the minute taking process to add presentation points and timestamps to the reports in the official minutes. • Amend the Policy such that "all topics and supporting material for an agenda will be submitted to the staff member preparing the agenda by 12:00 noon three (3) business days before a regular scheduled meeting.	
Seventh Amendment	
Notice to Council:	*September 13, 2022*
Approval:	*September 27 ,2022*
Description: Amend Appendix K, section 3.1 to read " the committee will consist of 10 members as follows: 3 resident members from the former Municipality of West Hants area (excluding Hantsport) who are not council members or municipal employees, 2 residents from the community of Hantsport who are not council members or municipal employees, 2 resident members from the community of Windsor who are not council members or municipal employees and 3 members of Council.	
Eighth Amendment	
Notice to Council:	*October 11, 2022*
Approval:	*October 25, 2022*

Description: • Amend Appendix M to reflect the changes noted in Attachment B (Section 4.1 to reflect that the committee will consist of seven (7) voting members (to ensure all perspectives are represented and side in a tie breaking scenario that promotes progression without uncertainty, and ten (10) non-voting supporting members as follows: Seven (7) resident members of diverse race and ethnicity (including, but not limited to, those from the African Descent, Acadian, Glooscap First Nation, LGBTQ+, Indigenous, 2SLGBTQIA+, Senior, Youth, and Newcomers' communities) (One (1) Supporting and Promoting Equality in our Communities (SPEC) Community Group Representative (non-voting), One (1) RCMP Representative (non-voting), One (1) Community Health Board Representative (non-voting), Six (6) non-voting staff members appointed by the Chief Administrative Officer and One (1) Councillor and 1 Alternate (non-voting) • Amend Section 10.16 of the Policy to read: "a meeting of Council or Committee of Council will adjourn at 10:00 pm unless otherwise determined by a majority vote of the members present. if the meeting agenda is not complete as of 10:00 p.m., the meeting will resume the next business day at 6:00pm to complete the work from the previous day's approved agenda.	
Ninth Amendment	
Notice to Council:	*January 10, 2023*
Approval:	*January 24, 2023*
Description: • Amend Section 1.3 (j) to include the definition of "Electronic means". The use of any technology that enables the public and all meeting participants to see and hear each other as the meeting is occurring." • Amend Section 5.8 to read "A Council meeting or Committee meeting may be conducted by electronic means pursuant to Section 19A (1) of the MGA." a) One or more Council or Committee members participating in a meeting by electronic means is deemed to be present at the meeting for purposes of quorum and voting. b) Except as provided in section 5.8, all attempts will me made for Council or Committee members to attend Meetings in-person. c) Council or Committee member will provide sufficient notice to the Chair or Clerk (prior to the meeting) of the circumstances that prevent them from attending the meeting in person. This notice	

should clearly indicate that the circumstances are beyond the control of the Council or Committee member, and that all reasonable efforts have been made to resolve the situation so that they are able to attend the meeting in-person.

d) It is the responsibility of the Councillor or resident member to ensure provision of electronic means at their location;

e) If used during a closed meeting, the member will ensure confidentiality is maintained at all times;

f) Every intention will be made that no Councillor or resident member participates by electronic means in no more than four (4) regularly scheduled meetings per year; with the awareness that emergencies occur.

g) The Councillor, resident member or members of the public does not interfere and/or disrupt the meeting, and if such occurs the Chair has the right to end the electronic participation;

- Amend Section 7.7 and 7.8 to read as 5:00 p.m.
- Amend Section 7.10 to add "and the majority of Council accept the report"
- Amend Section 7.11 to read as "Late additions to the agenda will be accepted if approved by the majority of Council at the meeting."
- Amend Section 7.12 to include "once approved by the majority of Council."
- Amend Section 9.12 to read as "electronic means" and remove audio and video.
- Amend Section 10.14 to read as "For purposes of efficiency and time management it will be the goal when setting an agenda to limit a maximum of two (2) formal presentations at any Committee of the Whole meeting, it will be at the discretion of Council to approve presentations at Council meetings."
- Amend Section 14.5 to include "These meetings will be recorded electronically for accuracy in the minute taking process."
- Amend Appendix D, Section 4.1 to include "and One (1) Alternate"
- Amend Section 17.3 to include the Police Advisory Board (PAB).
- Amend the Policy to include an Appendix N, for the Police Advisory Board.
- Amend Section 17.7 to include the Highway 101 Twinning Community Liaison Committee (CLC)

Tenth Amendment	
Notice to Council:	*January 9, 2024*
Approval:	*January 23, 2024*

Description: • Amend Section 9.4 to include "Informational sessions hosted by the Municipality will be recorded using audio and video equipment to accurately reflect information sharing. These meetings will be later uploaded to the Municipal Facebook page for transparency. No written minutes will be available for these meetings". • Amend Section 14.5 to include the wording "unless determined by Council to cease audio/video recording during the discussion". Amend Appendix D Committee Composition • The AAC will consist of a minimum of seven (7) members as follows: • Add the wording "No less than" to Resident members Amend Appendix L • Committee name changed from Municipal Climate Change Action Plan (MCCAP) to Climate Action Committee. • Amend Section 1.1 to read as "The Climate Action Committee provides a forum for all municipal departments and Council representatives to work co-operatively on implementing and evaluating the adaptation and mitigation actions outlined in the Climate Action Plans of the Municipality. These policy and adaptation procedures help protect people, properties, special places, and municipal infrastructure from the negative impact of climate change". • Remove Section 2(a) "MCCAP Committee" means the Climate Action Plan Committee. • Amend Section 4.3 to remove "MCCAP" wording and replace with Climate Action. Amend Appendix M • Section 4.1 to read as the Committee will consist of eight (8) voting members to ensure all perspectives are represented and removing the wording "and side in a tie breaking scenario that promotes progression without uncertainty". • Add Section 5.3 "Resident Members may be reappointed for a maximum of three (3) terms".	
Eleventh Amendment	
Notice to Council:	*July 24, 2024*
Approval:	*July 24, 2024*
Description: Amend Section 16 to read as "during the allotted twenty (20) minutes of Public Participation on all advisory committee agendas. A member of the public may speak for a maximum of five (5) minutes each during this period	
Twelfth Amendment	
Notice to Council:	*January 14, 2025*

Approval:	*January 28, 2025*

Description:

***Section 6.2**, the wording "the very first term being April 1, 2020 - October 31, 2022 and the nomination process be held again for a term of November 2022 – October 2024, at which time it will re-align with municipal elections in Nova Scotia" be removed and replaced with the wording "and aligns with municipal elections in Nova Scotia" was added for clarity.*
***Section 7.4** the deadline for all topics and supporting material for an agenda will be submitted to the staff member preparing the agenda by 12:00 noon be changed from three (3) days to five (5) days.*
***Section 7.6**, the word "should" be changed to the word "must".*
***Section 9.9**, add wording "the only person(s)".*
***Section 9.11,** removes the wording" but residents may leave messages; however, staff will be unable to address said messages" to align with the revised practiced during meetings.*
***Section 17.3 (c) and (d)** be repealed.*
***Section 17. 7(c)**, add the word "Cogmagun".*
***Section 17.8**, remove the wording" For clarification, the first appointment after April 1, 2020 will be in November 2022".*
***Section 17.11**, adds the wording "for Elected Official's".*
***Section 17.12**, adds the wording" residing in West Hants Regional Municipality".*
***Appendix F** - Appealed*
***Appendix G** – Appealed*
***Appendix J** - 4.2 (c) – add the wording" on an as needed basis".*
***Appendix K**, Section 3.1: Committee composition to read "the committee will consist of fourteen (14) members as follows: two (2) resident members appointed at large from West Hants Regional Municipality who are not municipal employees and all twelve (12) members of Council.*
***Appendix 0** – Newly combined Davidson Lake and French Mill Brook Watershed Advisory Committee.*

Thirteenth Amendment

Notice to Council:	*February 11, 2025*
Approval:	*February 25, 2025*

Description: Amend Appendix K, Section 3.1: Committee composition to read "the committee will consist of ten (10) members as follows: three (3) resident members from the former Municipality of West Hants area (excluding Hantsport) who are not Council members or Municipal Employees, two (2) resident members from the community of Hantsport who are not Council members or Municipal Employees, *two (2) resident members from the community of Windsor who are not Council members or Municipal Employees and three (3) members of Council.*

WEST HANTS REGIONAL MUNICIPALITY REPORT

Information ☒	Recommendation ☐	Decision Request ☐	Councillor Activity ☐

To: Climate Action Committee (CAC)

Submitted by: ___________________________________

John Ogilvie, Climate Action Coordinator

Date: 2025-04-09

Subject: Solar Energy Feasibility Study

RECOMMENDATION

As this is an information report, there are no recommendations from staff.

BACKGROUND

Property ☒	Public Opinion ☐	Environment ☒	Social ☐	Economic ☒	Councillor Activity ☐

Council awarded the contract to perform a solar energy feasibility study to CBCL Limited in May 2024. This study is funded with a grant from the Nova Scotia Department of Natural Resources and Renewables' (NS DNRR) Low Carbon Communities program, in the amount of $75,000 and a contribution of $25,000 from municipal sources. Following that, staff worked with CBCL to kick off the study and gather all required information.

DISCUSSION

Throughout the summer of 2024, staff worked with consultants from CBCL Limited to complete the solar energy feasibility study. This involved gathering 2 years' worth of facility electricity consumption, facility drawings to confirm structural designs, and site visits. During the site visits at each site, the consulting engineers assessed topography, electrical interconnection capabilities, and structural capabilities for sites with buildings that have potential for rooftop solar.

The study assessed the cost of installing solar energy at each site using monofacial (one-sided) (1-sided) or bifacial (two-sided) (2-sided) solar panels, the cost of electrical upgrades and supporting infrastructure, the potential energy production and greenhouse gas emissions avoided, the payback period, and other considerations like the necessity of structural or geotechnical investigations. Importantly, the study did not provide detailed structural assessments or geotechnical studies as they were outside the scope and budget of this project.

CBCL recommended if the Municipality considers the options in the study, geotechnical assessments should be completed for ground-mount installations and structural assessments should be completed for the facilities. Many of the facilities included in the study were not designed with solar panels in mind, so most need roof replacement or electrical upgrades before solar panel installation. Each facility has unique considerations for solar such as:

- The Falmouth Wastewater Treatment Plant (WWTP) (48 Falmouth Connector Rd) should undergo roof replacement with sheet metal before installing solar panels. Replacement with a metal roof would also improve the structural capacity of the roof for solar panels.
- The Brooklyn Fire Station 1 and Civic Centre (995 Hwy 215) should undergo extensive structural investigation before installing solar panels, as the loading requirements for this type of structure have changed with building code updates.
- The Windsor Water Treatment Plant (WTP) (786 Windsor Back Rd) should undergo roof replacement with a different roof style to reduce dead loading, which may allow for the weight of solar panels to be acceptable.
  - The expansion being designed for this plant should consider solar panels from the beginning.
- The studies of ground mounted solar panels at the capped Cogmagun landfill, Falmouth WWTP, Windsor WTP, Windsor Wastewater Lagoons (both new and old; 293 Wentworth Rd and 3 Lagoon Dr), and Brooklyn Fire Station 1 all resulted in a recommendation of detailed geotechnical assessments. The ground and land at each of these sites has been modified, and in the case of the wastewater treatment plants and capped landfill, disturbance of or, damage to, the liners is not acceptable.

As demonstrated in the conclusion of the study, the net-present value of each assessed project except for the Windsor WWTP at 293 Wentworth Rd the “new lagoons”, is negative. This indicates that the expected rate of return is less than the discount rate, meaning the project is not expected to create financial value. Although each site’s public visibility was discussed, CBCL did not assess social, political, or other considerations when considering the value of these projects. Additionally, CBCL did not consider grants or other contributions that may lower the cost of these projects to the Municipality; the funding scenarios considered if the Municipality took on debt to finance solar projects if the cost was above $150,000. This may be considered the highest cost scenario, as most grants come as non-repayable funding that the Municipality could apply for.

Due to CBCL’s proposal coming in under budget, NS DNRR has given WHRM an extension on the grant funding to June 27, 2025. This will allow staff to consider additional sites to use the remaining budget funding, otherwise the Municipality will be required to pay unused portions of the grant back to the Province. Since the structural assessment of the Windsor Community Centre (78 Thomas St) will be used to also consider solar on that building, WHRM and NS DNRR staff are exploring using remaining funds for this project to support the structural assessment.

The WHRM Solar PV Feasibility Study by CBCL is attached to this report for the Committee to review and discuss.

NEXT STEPS

Following Committee discussion and consideration of this study, climate action staff will continue investigating funding sources to augment budget allocations for solar energy. Staff will continue to investigate opportunities for solar energy as part of facility renewal, renovations, and new construction processes.

FINANCIAL IMPLICATIONS

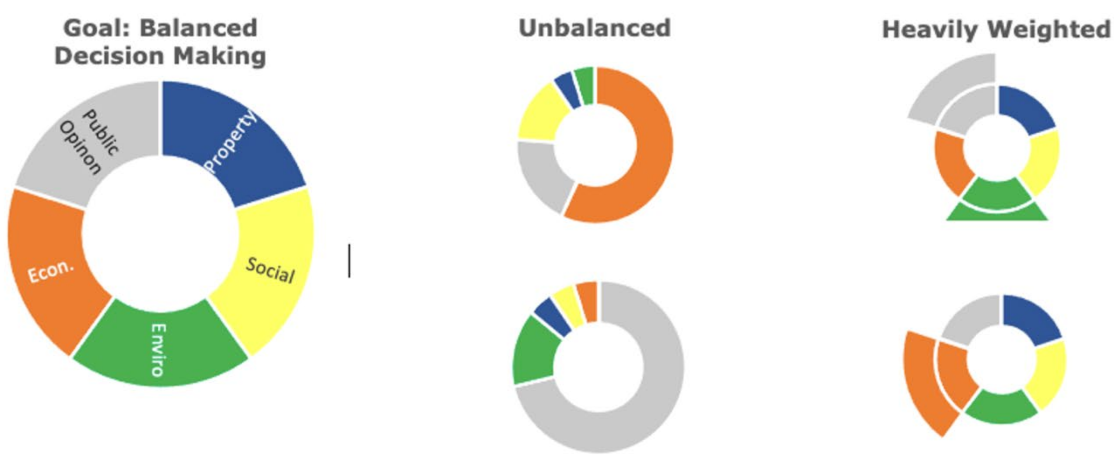
As this is an information report, there are no anticipated financial implications for the Municipality, however it will inform budgetary discussions with the Committee and Council about implementing solar energy at municipal facilities.

ATTACHMENTS

Attachment A WHRM Solar PV Feasibility Study

REVIEW

The Committee has been provided with a reference taken from the *Meeting and Committee Procedural Policy*, Appendix C "Decision Making by Council and Committee of the Whole", as a reminder of the principles highlighted for good decision making.



Report Prepared by: ___________________________________

John Ogilvie, Climate Action Coordinator

Report Approved by: ___________________________________

Kari Fougere, Acting Director of Planning and Development

Attachment A

Solar PV Feasibility Study

West Hants Regional Municipality

Draft Report

CBCL

247551.00 • September 2024

A	Issued for Review	M. Casimirri	12-Sep-2024	N. Downing
Rev.	Issue	Reviewed By:	Date	Issued By:

Project No. 247551.00

Maritime Centre, 1505 Barrington Street, Suite 901, Box 606, Halifax, NS,
B3J 2R7 | 902-421-7241 | CBCL.ca | info@CBCL.ca

September 12, 2024

John Ogilvie, EIT
Climate Action Coordinator
West Hants Regional Municipality
PO Box 3000, 76 Morrison Dr, Windsor NS
Email: Jogilvie@westhants.ca

Dear John:

RE: West Hants Regional Municipality – Solar PV Feasibility Study

CBCL Limited (CBCL) is pleased to present the draft report for the West Hants Regional Municipality Solar PV Feasibility Study.

Please do not hesitate to contact the undersigned if you should have any questions. Thank you.

Yours very truly,

CBCL Limited

Prepared by:
Nicole Downing, EIT
Junior Mechanical Engineer
Direct: (902) 492-7979 x2820
Email: ndowning@cbcl.ca

Reviewed by:
Marcos Casimirri, M.Eng., CEM, P.Eng.
Project Manager – Senior Mechanical Engineer

Project No.: 247551.00

Executive Summary

CBCL Limited (CBCL) was engaged by the West Hants Regional Municipality to conduct a solar photovoltaic (PV) feasibility study of six (6) sites located in the municipality as listed, in no particular order, below:

- 1379 Walton Woods Road – Capped 1st Generation Landfill
- 995 Highway 215 – Brooklyn Fire Station 1 and Civic Centre
- 293 Wentworth Road – Windsor Wastewater Treatment Plant "New Lagoons"
- 48 Falmouth Connector – Falmouth Wastewater Treatment Plant
- 3 Lagoon Drive – Windsor Wastewater Treatment Plant "Old Lagoons"
- 786 Windsor Back Road – Water Treatment Plant

Sites were evaluated for their eligibility for NSPI's net metering program or Nova Scotia's Community Solar Program depending on building energy consumption, available roof or ground area for PV installation, and location.

NSPI allows the installation of PV systems of a minimum size of 27 kW AC up to a maximum 1000 kW AC array for net metering if the NSPI customer has a demand meter. If the facility does not have an NSPI account with demand charges, or it is not a winery, farm, or licensed aquaculture plant, the facility could have a PV system with a capacity between 27 and 200 kW AC. Under this scenario, if the facility owner has multiple accounts with NSPI, the PV system can supply electricity to other accounts owned by the same person/institution as long as they are within the same geographical area known as NSPI distribution zone. Annual PV production cannot be higher than the building's annual electricity consumption to qualify for net metering[1].A larger PV system can also be considered for this site as long as the system does not export energy to the grid.

The Community Solar Program offered by the province of Nova Scotia provides an incentive for the installation of 0.5 MW AC up to a maximum 10 MW AC[2]. The community solar PV system must be interconnected directly to NSPI's transmission system. The program is eligible to municipalities within the province. Participants of the program enter into a power purchase agreement with NSPI in which the client submits a proposed fixed-rate per kilowatt-hour generated, a minimum of $0.07/kWh, that is locked in for 25 years. The participant is also responsible for obtaining subscribers for the PV system, which must meet the criteria laid out by the Nova Scotia Community Solar Program, the guidelines of which are presented in Appendix A.

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[1] Source: Commercial Net Metering| Nova Scotia Power (nspower.ca). Retrieved: 2024-07-31
[2] Source: Community Solar Program | Department of Energy and Mines (novascotia.ca). Retrieved: 2024-07-31

This study included modelling of the proposed PV system in PVSyst. This 3D modelling software allows the estimation of system size, equipment capacities, and energy production, among other outputs. The financial analysis considered the installed cost of the PV system, maintenance cost, and electrical upgrade cost. This analysis also considered the degradation of power production over time from the PV modules and string inverter replacement cost after ten (10) to twelve (12) years of operation, which results in a high maintenance cost in year 11 or 12.

The following PV system arrangements were assessed per site to determine which system shows the better financial performance, such as the lowest levelized cost of electricity (LCOE) and simple payback. Each system was assessed considering standard panels (monofacial) and bi-facial panels:

1. **1379 Walton Woods Road – Capped 1st Generation Landfill**
    - **Option A:** 3203 kWp DC, 2752 kW AC PV system with monofacial panels. Community Solar.
    - **Option B:** 3203 kWp DC, 2752 kW AC PV system with bifacial panels. Community Solar.
2. **995 Highway 215 – Brooklyn Fire Station 1 and Civic Centre**
    - **Option 1A:** 195 kWp DC, 188 kW AC PV system with monofacial panels. Net metering.
    - **Option 1B:** 178 kWp DC, 150 kW AC PV system with bifacial panels. Net metering.
    - **Option 2A:** 646 kWp DC, 563 kW AC PV system with monofacial panels. Community Solar.
    - **Option 2B:** 642 kWp DC, 563 kW AC PV system with bifacial panels. Community Solar
3. **293 Wentworth Road – Windsor Wastewater Treatment Lagoons**
    - **Option A:** 330 kWp DC, 300 kW AC PV system with monofacial panels. Net metering.
    - **Option B:** 327 kWp DC, 300kW AC PV system with bifacial panels. Net metering.
4. **48 Falmouth Connector – Falmouth Wastewater Treatment Plant**
    - **Option A:** 144.7 kWp DC, 130 kW AC PV system with monofacial panels. Net metering.
    - **Option B:** 143.7 kWp DC, 130 kW AC PV system with bifacial panels. Net metering.
5. **3 Lagoon Drive – Windsor Wastewater Treatment Plant 'Old Lagoons'**
    - **Option A:** 308 kWp DC, 275 kW AC PV system with monofacial panels. Net metering.
    - **Option B:** 279 kWp DC, 250 kW AC PV system with bifacial panels. Net metering.
6. **786 Windsor Back Road – Windsor Water Treatment Plant**
    - **Option A:** 178 kWp DC, 160.2 kW AC PV system with monofacial panels. Net metering.
    - **Option B:** 178 kWp DC, 160.2 kW AC PV system with bifacial panels. Net metering.

The following list includes all the assumptions and variables considered for the technical and financial analysis of both roof and ground mounted PV systems.

- Solar PV modules capacity: monofacial 555 W; bifacial 550 W
- Inverter: String inverter

- PV panel orientation and angle: due south at a 40° angle for ground mounted
- Roof mounted arrays were considered monofacial for all options
- PV system modelled with software PVSyst
- Building electricity consumption (Net metering only)
- Power Purchase Rate: $0.12/kWh (Community Solar only)
- General Inflation rate: 3%
- NSPI Electricity Inflation Rate: 4%
- O&M Inflation Rate: 4%
- Discount rate: 6.5%
- Interest rate: 6.5%
- Life of the project: 25 years
- Equity Ratio: 100% equity if capital <$150,000. If capital is >$150,000, consider $150,000 as equity and the rest as a loan, 20 year loan term if capital >$150,000.
- NS Power GHG emission intensity factor: 0.4506 CO2e kg/kWh in 2023[3]
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr
- String inverter replacement cost in year 12 (10% of CAPEX)

The summary of the analysis for each site is shown in Table ES.1, which shows the result from the analysis of the best option (option with bifacial panels) for each site considering the net metering or Community Solar scenario, depending on the site. The highest LCOE was determined to be $0.51340/kWh for the net metering arrangement at the Windsor WTP located at 786 Windsor Back Road. However, the lowest LCOE was determined to be $0.3513/kWh, which was found for the community solar arrangement at 1379 Walton Woods Road. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE also allows us to compare "apple to apples" when reviewing different projects.

[3] Source: https://www.nspower.ca/cleanandgreen/air-emissions-reporting. Retrieved: 2024-08-09

Table ES.1: Financial Analysis – Summary Results

Site	Option	Cost ($)	Total Savings [energy savings -maintenance cost] ($/yr)	LCOE $/kWh	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
1379 Walton Woods Road – Capped 1st Generation Landfill: Community Solar	Option B – 3203 kWp DC Bifacial	$9,442,224	$485,891	$0.3513	19.4	-$4,007,231	-	1987.4
Brooklyn Fire Station 1 and Civic Centre: Net metering	Option 1B - 178 kWp DC	$713,182	$35,919	$0.4297	19.9	-$15,838	1.8	41.9
Brooklyn Fire Station 1 and Civic Centre: Community Solar	Option 2B - 642 kWp DC Bifacial	$1,835,916	$94,194	$0.4125	19.5	-$1,122,548	-	87.2
293 Wentworth Road – Windsor WWTP: Net metering	Option B - 327 kWp DC Bifacial	$1,104,922	$62,765	$0.3799	17.6	$56,350	4.6	106.4
48 Falmouth Connector-Falmouth WWTP: Net metering	Option B – 143.7 kWp DC Bifacial	$548,275	$27,041	$0.4552	20.3	-$73,027	-0.80	88.6
3 Lagoon Drive – Windsor WWTP 'Old Lagoons': Net metering	Option B - 279 kWp DC Bifacial	$1,000,301	$50,975	$0.3904	19.6	-$45,214	2.2	69.9
786 Windsor Back Road - WTP: Net metering	Option B – 178 kWp DC Bifacial	$651,444	$33,199	$0.5134	19.6	-$125,050	-1.2	76.9

Net metered arrangement sites, such as 293 Wentworth Road and the Brooklyn Fire Station, show the highest annual cost savings and the highest NPVs over the term of the study. Also, the net metering option at 293 Wentworth showed the shortest payback period and the lowest LCOE among the net metering projects. For community solar arrangements, the 1397 Walton Woods Road and the Brooklyn Fire Station have similar simple payback periods.

In summary:

- For ground mounted PV arrays, bifacial panels are the best option.
- The simple payback period, for the majority of the projects, ranges from 19-20 years.
- All projects show a LCOE higher than the LCOE calculated for the purchase of electricity from the grid. LCOEs, for certain projects, can be lowered if there is a reduction in any of the following: debt terms, interest rates, or install costs.
- Costs considered in the analysis are preliminary costs provided by PV contractors and service providers. Therefore, it is expected that better (lower) costs should be obtained during a competitive tender process, which will include the technical specification of the systems to allow bidders to offer their best price.
- Costs considered in the projects do not include any potential incentives for which West Hants Regional Municipality may be eligible.
- The community solar options were analyzed considering an assumed PPA rate of $0.12/kWh. Any PPA rate with NSPI must be negotiated and agreed on with NSPI.
- Different sections of the report present sensitivity analyses that consider variations in capital cost, energy production, and PPA rates. These analyses allow the estimation of ranges for payback and LCOEs.
- The timelines estimated for each project are conservative. A shorter implementation time might be achieved, but depends on the equipment availability, contractor expertise, and equipment supply chain conditions.
- The net metering project with the shortest payback, lowest LCOE, and that offers good visibility to the public is at 293 Wentworth. It is worth mentioning that the final PV system sizes will depend on the results from the geotechnical assessments.
- The community solar project with the shortest payback, smallest LCOE, and largest GHG reduction impact is at the landfill. However, a full geotechnical study must be completed to determine the best solution for placing the solar systems while keeping the integrity of the capped cells.
- The community solar project at the Brooklyn Fire Station has a higher payback and LCOE compared to the project at the landfill. However, this solar array would be located by a community centre, and therefore, more visible to the public where it could serve as an example for the community.
- The implementation of any of the solar PV options will result in a reduction of GHG emissions purchased from the grid ranging from 41.9 to 1987.4 tonnes per year. The PV arrangement at 293 Wentworth Road shows the smallest simple payback period and the highest carbon saving (tonnes), of the net metering sites, at 106.1 tonnes. While 1379 Walton Woods Road shows reduction of 1987.4 tonnes of emissions purchased from the grid.

- If a rooftop PV project is considered for implementation, it is advised that the recommendations in this report be followed. PV systems cannot be installed on roofs that are at or near the end of their service life.

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Appendices

A Nova Scotia Community Solar Program Guidelines
B PVSyst Reports

1 Introduction

1.1 Background

CBCL Limited (CBCL) was engaged by the West Hants Regional Municipality to conduct a solar photovoltaic (PV) feasibility study of six (6) sites located in the municipality as listed in no particular order below:

- 1379 Walton Woods Road – Capped 1st Generation Landfill
- 995 Highway 215 – Brooklyn Fire Station 1 and Civic Centre
- 293 Wentworth Road – Windsor Wastewater Treatment Plant “New Lagoons”
- 48 Falmouth Connector -Falmouth Wastewater Treatment Plant
- 3 Lagoon Drive – Windsor Wastewater Treatment Plant “Old Lagoons”
- 786 Windsor Back Road – Water Treatment Plant

This report is a preliminary assessment in which relevant information has been gathered to discover the potential for the installation of a PV system, and what approximate impact such an installation could achieve with respect to energy use, building GHG emissions, and ultimately, the anticipated annual energy savings.

1.2 Methodology

A site visit was conducted on July 11, 2024, to inspect the facilities. The objective of the visit was to observe the available ground and roof areas and potential shading issues on any ground areas caused by nearby obstacles (building structure, chimneys, power poles, etc.) Interviews with building operations staff assisted with understanding the building occupancy schedule and operating load.

Information from the electric utility bills, encompassing the latest two years (2022-2023), was reviewed to develop energy consumption trends and understand the consumption profiles at the facility. Array capacity was determined based on the current consumption and the limits of the NSPI net metering program and Community Solar Program (where possible). Solar PV systems were also analyzed from the financial point of view, which assisted in determining the payback and levelized cost of energy (LCOE) generated by each PV system.

2 1379 Walton Woods Road – Capped 1st Generation Landfill

The capped 1st generation landfill located at 1379 Walton Wood Road in Centre Burlington, NS, does not currently have an electrical connection or meter. There is no energy consumption at this site.

2.1 Community Solar Program

The Community Solar Program offered by the province of Nova Scotia provides an incentive for the installation of 0.5 MW AC up to a maximum 10 MW AC[4]. The community solar PV system must be interconnected directly to NSPI's transmission system. The program is eligible to municipalities within the province. Participants of the program enter into a power purchase agreement with NSPI in which the client submits a proposed fixed-rate per kilowatt-hour generated, a minimum of $0.07/kWh, that is locked in for 25 years. The participant is also responsible for obtaining subscribers for the PV system, which must meet the criteria laid out by the Nova Scotia Community Solar Program, the guidelines of which are presented in Appendix A.

2.2 Considerations to Size the PV System

The site at 1379 Walton Wood Road does not have an electrical meter which makes it ineligible for the NSPI net metering program. This site will only quality for the Nova Scotia Community Solar Program which requires the installation of a 0.5 MW AC up to a maximum 10 MW AC[4].

[4] Source: Community Solar Program | Department of Energy and Mines (novascotia.ca). Retrieved: 2024-07-31

2.3 PV System

2.3.1 Ground Mounted

Figure 2.1: Typical Ground Mounted PV Array

A typical ground mounted system is shown in Figure 2.1. However, considering that the PV system would be on top of a capped landfill, a ballasted racking system is a more suitable solution. The implementation of a ground mounted racking system typically requires a geotechnical analysis of the site to be able to design the array foundations. The cost of the geotechnical analysis, as part of the detailed system design cost, is included in the capital cost estimate for this array. Also, alternative mounts such as single or dual axis tracking were not considered due to the additional maintenance requirements.

2.4 Incentive Programs

2.4.1 Low Carbon Communities Program

West Hants Regional Municipality may be eligible for the *Low Carbon Communities Program.* The program offers funding to recover up to 75% of the total project costs to a maximum of $75,000.The program provides 90% of the funding at the start of the project and the remaining 10% when the project is completed, and the final reports submitted. No more than 75% of the total project cost can be funded through the provincial government[5]. This program requires that reduction in GHG emissions be demonstrated. The expected reductions in capital cost for this project, due to this incentive program, are included in the financial analysis. Further details about the requirements from this program can be found here: Low Carbon Communities - Government of Nova Scotia, Canada. The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

2.4.2 Green Municipal Fund: Local Energy Generation

West Hants Regional Municipality may be eligible for the Green Municipal Fund's *Community Energy Systems: Capital Projects* grant and loan program. The program offers a combined grant and loan up to 80% of eligible project costs to a maximum of $10,000,000.

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[5] Source: Low Carbon Communities - Government of Nova Scotia, Canada. Retrieved: 2024-07-31

With the grant being eligible for up to 15% of project costs. This program requires the completion of a feasibility study which considers technical and financial, as well as the social and environmental impacts of the project[6]. Further details about the requirements from this program can be found here: Capital project: Community Energy Systems (greenmunicipalfund.ca).

2.4.3 Sustainable Communities Challenge Fund

West Hants Regional Municipality may be eligible for the *Sustainable Communities Challenge Fund: Mitigation Stream*. This fund provides grants up to 80% of eligible projects costs to a maximum of $1,000,000. The applicant must supply a minimum of 20% of eligible project costs, which may be made by alternate funding sources such as federal funding sources. This program requires that reduction in GHG emissions be demonstrated[7]. Further details about the requirements from this program can be found here: Funding Opportunities - Sustainable Communities Challenge Fund (nschallengefund.ca). The West Hants Regional Municipality will need inquire about when applications for this fund will reopen.

2.4.4 Low Carbon Economy Challenge

West Hants Regional Municipality may be eligible for the *Low Carbon Economy*. This fund provides grants up to 50% of eligible projects costs for provincial municipalities. The fund ranges from a minimum of $1,000,000 to a maximum of $25,000,000 in available funding. According to the program, the project must produce electricity for the facility's own use. Eligible projects must result in a reduction in GHG emissions. Further details about the requirements from this program can be found here: Low Carbon Economy Challenge Applicant Guide 2023 - Canada.ca.[8] The West Hants Regional Municipality will need inquire about when applications for this fund will reopen.

2.5 Technical-Financial and Life Cycle Analyses

The sizing and estimation of energy production from the PV system was completed with the modelling software PVSyst, which is one of the most recognized PV modelling software platforms in the world. The PVSyst model considered the building's load profile or energy consumption, the exact location of the PV array, the site's weather data and solar radiation, estimated near and far shading issues, and estimated panel soiling issues.

[6] Source: Capital project: Community Energy Systems (greenmunicipalfund.ca). Retrieved: 2024-07-31
[7] Source: Funding Opportunities - Sustainable Communities Challenge Fund (nschallengefund.ca). Retrieved: 2024-07-31
[8] Source: Low Carbon Economy Challenge - Canada.ca. Retrieved: 2024-07-31

This analysis included the installed cost of the PV system and, if applicable, financial incentives, and electrical upgrade cost. Additionally, this analysis considered the degradation in power production over time from the PV modules, string inverter replacement cost after ten (10) to twelve (12) years of operation, inflation rate, annual maintenance cost, and discount rate, among other variables. Usually for string inverters, the replacement cost is about 10% of the PV system installed cost.

Two different PV system arrangements were assessed to determine which system shows the better financial performance, such as the lowest levelized cost of electricity and simple payback. The system was evaluated considering standard panels (monofacial) and bi-facial panels. These options include:

1. **Option A:** 3203 kWp DC, 2752 kW AC PV system with monofacial panels. Community Solar.
2. **Option B:** 3203 kWp DC, 2752 kW AC PV system with bifacial panels. Community Solar.

2.5.1 Financial Assumptions

The following list includes all the assumptions and variables considered for the technical and financial analysis of both roof and ground mounted PV systems.

- Solar PV modules capacity: monofacial 555 W; bifacial x550 W
- Inverter: String inverter
- PV panel orientation and angle: due south at a 40° angle for ground mounted
- PV system modelled with software PVSyst
- Power Purchase Rate: $0.12/kWh
- General Inflation rate: 3%
- NSPI Electricity Inflation Rate: 4%
- O&M Inflation Rate: 4%
- Discount rate: 6.5%
- Interest rate: 6.5%
- Life of the project: 25 years
- Equity Ratio: 100% equity if capital <$150,000. If capital is >$150,000, consider $150,000 as equity and the rest as a loan, 20 year loan term if capital >$150,000.
- NS Power GHG emission intensity factor: 0.4506 CO_2e kg/kWh in 2023[9]
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr
- String inverter replacement cost in year 12 (10% of CAPEX)

2.5.2 PV Systems Cost

Solar PV contractors in Nova Scotia were contacted to obtain budgetary installed costs for the proposed PV system arrangements, including Supernova Solar, Wattup Solar, and

[9] Source: https://www.nspower.ca/cleanandgreen/air-emissions-reporting. Retrieved: 2024-08-09

Natural Forces. It was determined that the average installed price for PV arrays with monofacial or standard panels is $2,175-3,000/kWp DC and with bifacial modules is $2,200-$3,075/kWp DC, depending on the system size, racking system, inverter technology (string versus microinverter), and PV installer. These budgetary installed costs do not include HST. This pricing excludes the costs for a geotechnical analysis and any required electrical upgrades and structural modifications to accommodate the new PV system.

2.5.3 Geotechnical Analysis and Cost

Foundation designs of solar photovoltaic (PV) arrays commonly consist of ballasted footings founded at the ground surface (i.e., precast concrete pads), or anchored footings consisting of shallow, driven pile, or helical screw pile foundations embedded below ground. PV arrays also include supporting infrastructure such as service roads, storage shipping containers, electrical substations with transformers, concrete pads for electrical equipment, battery storage systems, etc. that each have their own unique foundation requirements.

Geotechnical investigations in support of PV arrays commonly consist of either test pit or borehole drilling investigations. The decision to excavate test pits versus drill boreholes is determined based on site specific requirements and considerations. A desktop study and site visit can help better define the geotechnical field investigation requirements. Underground utility locating should be completed prior to conducting the field investigations.

Geotechnical reports will often be structured in the following way:

- Introduction
- Project and Site Description
- Fieldwork Procedure
- Summarized Subsurface Conditions
- Discussions and Recommendations [including earthworks, foundation design for PVs and associated infrastructure (i.e., bearing capacity and settlement), slope stability, trenching, service roads, construction monitoring, etc.]

In-situ and laboratory testing on soils is conducted to characterize various index, strength, and environmental properties of the soils. This testing may include:

- Standard penetration testing (SPT)
- Moisture content
- Grain size analysis
- Proctor density
- Unconfined compressive strength (UCS) of rock
- Basic chemical testing relating to corrosion of buried concrete and steel including pH, sulphate, and chloride
- Thermal conductivity
- In-situ electrical resistivity
- Other in-situ strength tests as required
- Other environmental quality tests as required

2.5.3.1 Site Description

The site is located at the former Cogmagun Landfill at 1379 Walton Woods Road, Centre Burlington, NS. The site contains a capped landfill as shown in Figure 2.2 and Figure 2.3. It is our understanding that the landfill contains both household waste and construction waste fill. The thickness, composition, and soil quality of the waste is unknown.

It is our understanding that the landfill is a 'first-generation' landfill and may not contain a containment system (i.e., composite liner base). In the beginning of 2006, municipalities were required to switch from first-generation to second-generation landfills[10]. Second generation landfills contain a composite liner system. Although the landfill may not contain a composite liner, it is probable that it was still capped with a composite cover system as per the Municipal Solid Waste Landfill Guidelines[11]. A typical final cover cross section is shown in Figure 2.4. There may only be 300 mm of topsoil overlying the composite cover system. The fill material used to cap the landfill is unknown at this time. The PV arrays are proposed to be located on top of the capped landfill. Ballasted foundations are proposed to avoid damaging the cover system with anchored foundations.

Based on geologic mapping, the principal soil unit in the area is ground moraine and streamlined drift till. The till is described as silty, compact, material derived from both local and distant sources[12]. It is possible that the soil cover was constructed using reworked till excavated from the adjacent new West Hants Waste Management Facility.

Figure 2.2: Ortho – 1379 Walton Woods Road - Ballasted PV array area (yellow) (Google Earth, 2024)

[10] West Hants. 2024. GFL West Hants Landfill. [Online] Available at: https://www.westhants.ca/landfill-waste.html
[11] Nova Scotia Environment and Labour (NSE). 1997. Municipal Solid Waste Landfill Guidelines
[12] Stea, R.R., Conley, H., Brown, Y. (1992). Surficial Geology of the Province of Nova Scotia – Map 92-3.

Figure 2.3: LiDAR – 1379 Walton Woods Rd. (GeoNOVA, 2024)

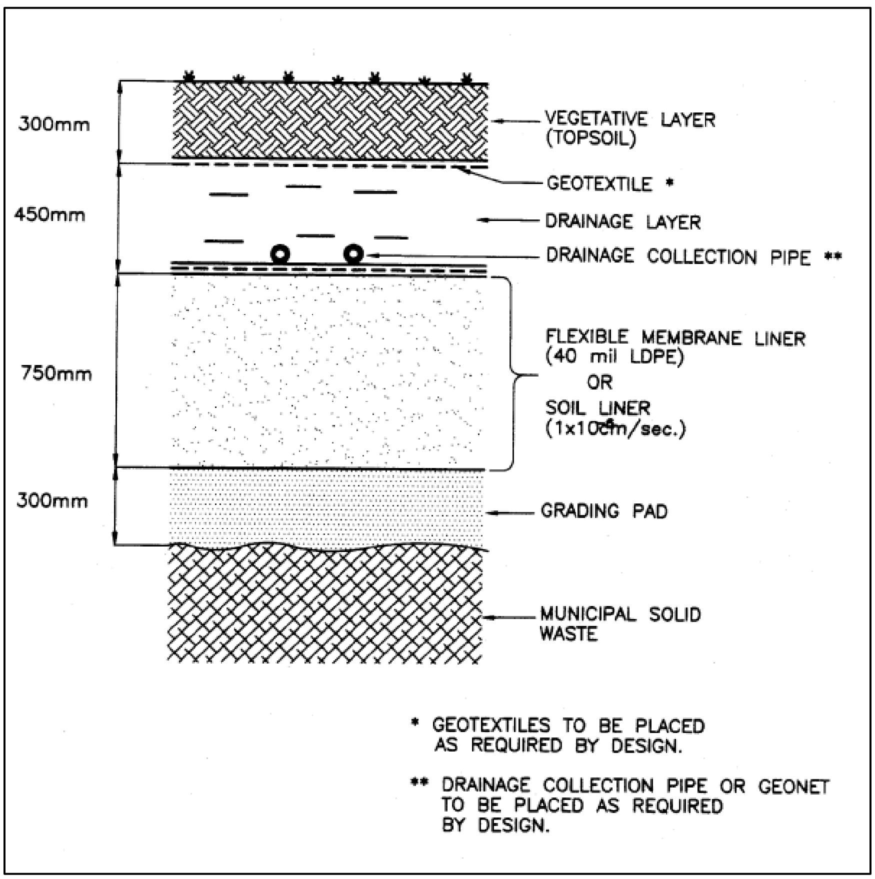

Figure 2.4: Typical Final Cover System Cross-Section (NSE, 1997)

2.5.3.2 Potential Geotechnical Challenges

Potential geotechnical challenges include:

- Unknown waste composition.

- Unknown waste thickness.
- Unknown soil quality.
- Unknown placement and compaction methods of waste.
- Unknown thickness and design of landfill cover system.
- Unknown type, placement, and compaction methods of soil cover system.
- Location of drainage swales, gas vent piping, etc.
- Damage to landfill cover during investigation and construction.
- Damage to the landfill cover system due to added weight of PV foundations (i.e., compression of drainage layer, or damage to drainage collection pipes).
- Bearing capacity.
- Slope stability.
- Differential settlement due to waste decay.
- Frost heave of landfill cover soils.
- Misalignment of ballasted PVs due to differential settlement or frost heave.
- PV system wiring may need to run through above-ground conduits and not in underground trenches to preserve cap function.
- Influence of PVs on vegetative cover, erosion control, and stormwater management.

2.5.3.3 Suggested Geotechnical Study

To support the PV array foundation design, the following geotechnical study is suggested:

- Desktop study and site visit to learn more about past landfill operations and cover system.
- Pending the results of the desktop study, either a test pit investigation, borehole investigation, or a combination of both.
- Approximately 16 test holes excavated in a grid across the cover.
- In-situ and laboratory testing and geotechnical report as described above in General Geotechnical Requirements.

2.5.3.4 Cost Estimate

The cost of the proposed geotechnical investigation would be in the range of $40k - $50k. Environmental testing, if required, could be extra.

2.5.4 Electrical Analysis and Cost

There is no existing electrical utility connection at this location so the project will be connected directly to the distribution system at line 18V-412. The distribution line that feeds the location today is an overhead three phase 24.4kV system, with a single-phase tap dead-ended into the landfill location. The maximum capacity of the line is 2.817MW, per the NSPI distribution feeder map, therefore, the capacity of the potential PV site is considered to be 2.8MW-AC (3.3-3.4 MW-DC). Please note that the final system size would ultimately be pending NSPI approval.

Since this system is greater than 100kW-AC, the NSPI Distribution Generator Interconnection Procedures (DGIP) apply. Additionally, the overhead line to the site (presently single phase) will have to be upgraded to three phase.

Given that this site does not require an interconnection with the existing electrical infrastructure, there are a number of practical "output" AC voltage options. An Owner-supplied step-up transformer will be required to interconnect with the 24.4kV distribution system. Given equipment availability, 480V is the practical low voltage option.

Table 2.1: Electrical Cost

Item	Estimated Cost	Notes
Overhead Line Upgrades	$11,000	Line upgrades are estimated at $85/m. Note: NSPI may provide the first 92m; reducing this cost by $7,650.
NSPI Interconnection Equipment	$50,000	NSPI will require the IPP to pay for the protective devices required to interconnect the site.
2 x 1500kVA Padmount Transformer	$250,000	
Primary Interconnection Equipment	$75,000	
2 x 2000A 480V Switchboard	$120,000	
Total	**$506,000**	

2.5.5 PV System – Community Solar

This PV system was sized considering the capacity limits for the community solar program, as well as the available usable land area on-site.

Figure 2.5 shows the 3D models in PVSyst and the area considered for the implementation of the PV system considering monofacial (Option A) and bifacial panels (Option B). The following items were considered when placing the PV system on this part of the property:

- No shading issues due to the proximity to nearby taller structures.
- Relatively flat surface.
- Excellent exposure to due south.
- Easy access for maintenance.
- Racking system will be ballasted

Figure 2.5: Ground Mounted PV Array – Option A and B

The estimated energy generation from the PVSyst model, as well as the estimated installed cost, an estimated PPA rate, and PV system specific production are presented in Table 2.2. The PVSyst reports are included in Appendix B. Costs in the table below do include HST.

Table 2.2: Ground Mounted PV System – Options A and B

1379 Walton Wood Road Capped 1st Generation Landfill – Community Solar	Option A – 3203 kWp DC Monofacial	Option B – 3203 kWp DC Bifacial
Ground Mount PV Capacity (kWp DC)	3203.0	3203.0
Ground Mount PV Capacity (kWp AC)	2752.0	2752.0
Ground Mount Installed Cost ($/kWp)	$2,667	$2,708
Ground Mount Cost [PV only] ($)	$8,542,401	$8,673,724
Electricity Rate ($/kWh)	$0.1200	$0.1200
Annual Consumption (kWh/yr)	-	-
PV Generation (kWh/yr)	4,085,308	4,410,495
PV Specific Production (kWh/yr/kWp)	1,275	1,377

When comparing the results for Option 1 considering monofacial panels (Option 1A) and bifacial panels (Option 1B), the following was observed:

- The installed cost per kWp for bifacial panels is approximately than 1.5% higher than for monofacial panels.
- All electricity generated by the PV system would be exported to the grid as part of a power purchase agreement.
- All energy produced onsite will generate revenue at the PPA rate (an estimated power purchase agreement of $0.12/kWh).
- The production and specific production from Option B (bifacial) are both 8% higher than from Option A, even though both options have the same kWp DC.

In addition to these PV costs, other costs should be considered in the financial analysis. Table 2.3 shows the PV installation cost, as well as the electrical upgrade cost, fencing, geotechnical analysis, and design cost. As expected, the highest installation cost is for Option B, which also results in the highest total cost.

Table 2.3: PV Cost and Additional Costs - Options A and B

Installed Cost	Option A – 3203 kWp DC	Option B – 3203 kWp DC Bifacial
PV Ground Mounted ($)	$8,542,401	$8,673,724
Geotechnical Analysis Cost ($)	$50,000	$50,000
Electrical Upgrade Cost ($)	$506,000	$506,000
Site Fencing ($)	$110,000	$110,000
Design ($)	$102,500	$102,500
Total Project Cost ($)	**$9,310,901**	**$9,442,224**

Considering all these costs and the total savings, the following tables show the simple payback, net present value for a 25-year project horizon, life cycle costs (LCC), and the CO_2 emission reductions. Total savings include the energy savings and annual maintenance cost. Maintenance cost includes cleaning the panels twice a year, tightening the mechanical and electrical connections once a year, spot measurements once a year, and remote review of the system performance every three or four months.

Table 2.4: Financial Analysis – Options A and B

1379 Walton Wood Road	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option A - 3203 kWp DC Monofacial	$9,310,901	$447,525	$490,237	20.8	-$4,333,042	-	1840.8
Option B - 3203 kWp DC Bifacial	$9,442,224	$485,891	$529,259	19.4	-$4,007,231	-	1987.4

Option A has a lower installation cost, but Option B results in higher savings, which results in Option B having a shorter simple payback period. The cash flow and LCOE for both projects should be reviewed to further assess these options. The cash flow includes the maintenance cost and the savings from the generated electricity. Typically, a PV system fitted with string inverters requires the replacement of the inverters after ten (10) to twelve (12) years of operation, which results in a high maintenance cost in year 11 or 12.

2.5.5.1 Levelized Cost of Energy (LCOE)

The LCOE measures lifetime costs divided by energy production. It calculates the present value of the total cost of implementing and operating the building over an assumed lifetime. LCOE allows the comparison of different PV projects and different technologies (e.g., wind, solar, natural gas) of unequal life spans, project size, different capital cost, risk, return, and capacities. Figure 2.6 shows the LCOE formula.[13]

The LCOE calculation for this project considered the following variables:

- O&M Inflation rate: 4%
- Discount rate: 6.5%
- Life of the project: 25 years
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr (the same as in the previous section).
- Inverter replacement cost in year 12 (10% of CAPEX)

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

I_t = Investment expenditures in year t (including financing)
M_t = Operations and maintenance expenditures in year t
F_t = Fuel expenditures in year t
E_t = Electricity generation in year t
r = Discount rate
n = Life of the system

Figure 2.6: LCOE Formula

Table 2.5 shows the costs included in the calculation of the LCOE and the estimated annual energy production factoring power production depreciation. The LCOE for Option A was determined to be $0.3739/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system.

Table 2.5: LCOE Calculation – Option A

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000		-	-
1	-	$821,769	-$42,712	4,085,308
2	-	$821,769	-$44,420	4,044,455
3	-	$821,769	-$46,197	4,024,233
4	-	$821,769	-$48,045	4,004,111
5	-	$821,769	-$49,967	3,984,091
6	-	$821,769	-$51,966	3,964,170
7	-	$821,769	-$54,044	3,944,350
8	-	$821,769	-$56,206	3,924,628
9	-	$821,769	-$58,454	3,905,005
10	-	$821,769	-$60,793	3,885,480

[13] Source: https://www.energy.gov/sites/prod/files/2015/08/f2/LCOE.pdf. Retrieved: 2020-02-05

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
11	-	$821,769	-$63,224	3,866,052
12	-	$821,769	-$919,993	3,846,722
13	-	$821,769	-$68,383	3,827,488
14	-	$821,769	-$71,119	3,808,351
15	-	$821,769	-$73,963	3,789,309
16	-	$821,769	-$76,922	3,770,363
17	-	$821,769	-$79,999	3,751,511
18	-	$821,769	-$83,199	3,732,753
19	-	$821,769	-$86,527	3,714,090
20	-	$821,769	-$89,988	3,695,519
21	-		-$93,587	3,677,042
22	-		-$97,331	3,658,656
23	-		-$101,224	3,640,363
24	-		-$105,273	3,622,161
25	-		-$109,484	3,604,050

The LCOE for Option B was determined to be $0.3513/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system.

Table 2.6: LCOE Calculation – Option B

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000	-	-	-
1	-	$833,550	-$43,369	4,410,495
2	-	$833,550	-$45,103	4,366,390
3	-	$833,550	-$46,907	4,344,558
4	-	$833,550	-$48,784	4,322,835
5	-	$833,550	-$50,735	4,301,221
6	-	$833,550	-$52,765	4,279,715
7	-	$833,550	-$54,875	4,258,316
8	-	$833,550	-$57,070	4,237,025
9	-	$833,550	-$59,353	4,215,840
10	-	$833,550	-$61,727	4,194,761
11	-	$833,550	-$64,196	4,173,787
12	-	$833,550	-$934,136	4,152,918
13	-	$833,550	-$69,435	4,132,153
14	-	$833,550	-$72,212	4,111,492
15	-	$833,550	-$75,100	4,090,935
16	-	$833,550	-$78,104	4,070,480

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
17	-	$833,550	-$81,229	4,050,128
18	-	$833,550	-$84,478	4,029,877
19	-	$833,550	-$87,857	4,009,728
20	-	$833,550	-$91,371	3,989,679
21	-		-$95,026	3,969,731
22	-		-$98,827	3,949,882
23	-		-$102,780	3,930,133
24	-		-$106,891	3,910,482
25	-		-$111,167	3,890,930

Table 2.7 summarizes the results of the financial assessment for both options. Option B shows the highest NPV and lower LCOE compared to Option A.

Table 2.7: Summary - Financial Analysis - Options A and B

1379 Walton Wood Road	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	LCOE $/kWh	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option A - 3203 kWp DC Monofacial	$9,310,901	$447,525	$0.3739	20.8	-$4,333,042	-	1840.8
Option B – 3203 kWp DC Bifacial	$9,442,224	$485,891	$0.3513	19.43	-$4,007,231	-	1987.4

Considering that Option B was shown to have the highest NPV and lower LCOE compared to Option A, a sensitivity analysis around the total implementation cost was performed. Table 2.8 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

2.5.5.2 Sensitivity Analysis – CAPEX

A sensitivity analysis around the total implementation cost was performed. Table 2.8 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

Table 2.8 CAPEX Sensitivity Analysis

PV System	CAPEX Variance +/-%	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	LCOE ($/kWh)	Utility LCOE ($/kWh)
Option B - 3203 kWp DC Bifacial	0%	$9,442,224	$447,525	$490,237	19.4	-$4,007,231	-	$0.3513	$0.1200
	30%	$12,274,891			25.3	-$7,157,708	-	$0.4574	$0.1200
	-20%	$7,553,779			15.5	-$1,906,913	-7.2	$0.2806	$0.1200

2.5.5.3 Sensitivity Analysis – Energy Generation

A sensitivity analysis around the total energy generation was performed. Table 2.9 shows what the simple payback and LCOE range would be if the electricity generation varied between -5% and +5%.

Table 2.9: Sensitivity Around kWh/yr Generation

PV System	+/- % kWh/yr	kWh/yr	Total Savings ($/yr)	Simple Payback (yr)	LCOE $/kWh	Utility LCOE $/kWh)
Option B - 3203 kWp DC Bifacial	-	4,410,495	$485,891	19.43	$0.3513	$0.1745
	-5%	4,189,970	$459,428	20.55	$0.3698	$0.1745
	5%	4,631,020	$512,354	18.43	$0.3346	$0.1745

2.5.5.4 Sensitivity Analysis – Power Purchase Rates

A sensitivity analysis around the power purchase rate was performed. Table 2.10 shows what the simple payback, savings and NPV range would be if the power purchase rate varied between -20% and +20%.

Table 2.10: Sensitivity Around Power Purchase Rate ($/kWh)

PV System	+/- % ($kWh/yr)	PPA Rate (kWh/yr)	Total Savings ($/yr)	Simple Payback (yr)	NPV ($)
Option B - 3203 kWp DC Bifacial	-	$0.1200	$485,891	19.4	-$5,290,434
	-20%	$0.0960	$380,039	22.8	-$2,896,001
	20%	$0.1440	$591,743	14.7	-$2,724,028

2.6 PV Project Estimated Timeline

The implementation of any of these projects will require the completion of a number of tasks. Considering that an engineering company produces the design and tender package, and a solar PV contractor installs the system (turn-key project), a project timeline was estimated. The tables below depict the estimated timeline to complete the options described for this site.

Table 2.11: Estimated Timeline for Option A and B

Task #	Option A and B- Tasks - 3203 kWp Monofacial and 3203 kWp Bifacial PV Systems	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
1	RFP process to design and create the tender package for the PV system. Select PV designer. If WHRM requires an Engineer to act as Owner's Engineer, an RFP to select it could occur in parallel to the RFP to select the PV designer.	6	6	weeks after RFP was issued
2	PV Designer: Kick-off Meeting, Available Information Review	1	7	weeks after RFP was issued
3	PV Designer: Site Visit	1	8	weeks after RFP was issued
4	PV Designer: PV System Design and Tender Package Preparation	8	16	weeks after RFP was issued
5	WHRM: Design and Tender Package Review	1	17	weeks after RFP was issued
6	PV Designer: Design and Tender Package Update According to WHRM Comments	1	18	weeks after RFP was issued
7	WHRM: Tender Package Is Issued	1	19	weeks after RFP was issued
8	Bidders: Tender Period, Question and Answer Period. Bids are submitted to WHRM.	4	23	weeks after RFP was issued
9	WHRM or Owner's Engineer: Bid Assessment, Question and Answer with bidders, Bids Ranking and Recommendation. Successful bidder is contacted.	3	26	weeks after RFP was issued
10	WHRM: Negotiation with Successful Bidder. Contract signing.	2	28	weeks after RFP was issued
11	PV Contractor: Kick-off Meeting, Available Information Review, Site Visit.	2	30	weeks after RFP was issued
12	PV Contractor: Equipment Selection and Acquisition. PV System Installation.	22	52	weeks after RFP was issued
13	WHRM or Owner's Engineer: Design drawings and Shop Drawings Review. Site visits. Communications with PV Contractor (in parallel to above)	22	52	weeks after RFP was issued

Task #	Option A and B- Tasks - 3203 kWp Monofacial and 3203 kWp Bifacial PV Systems	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
14	PV Contractor: System Start-up	1	53	weeks after RFP was issued
15	WHRM or Owner's Engineer: As-built Document and Drawings Review. System Commissioning. Commissioning Report.	4	57	weeks after RFP was issued

3 995 Highway 215 – Brooklyn Fire Station 1 and Civic Centre

3.1 Review of Historic Energy Performance

The Brooklyn Fire Station 1 and Civic Centre located at 995 Highway 215 in Newport, NS, provided electricity bills for a 24-month period spanning January 2022 to December 2023.

Energy consumption and demand were reviewed in annual terms to ensure that variation in seasonality was observable. With at least two periods available, a month-to-month comparison of the facility's energy performance was made from one year to the next. Review of electricity consumption profiles based on the information obtained from the two periods was discussed and is compared in this section. This review will also include observed variations in electricity demand by month across the two annual periods.

3.1.1 Electricity Use Profiles

Figure 3.1 provides the monthly electricity usage profile which shows the 24-month period from January 2022 to December 2023.

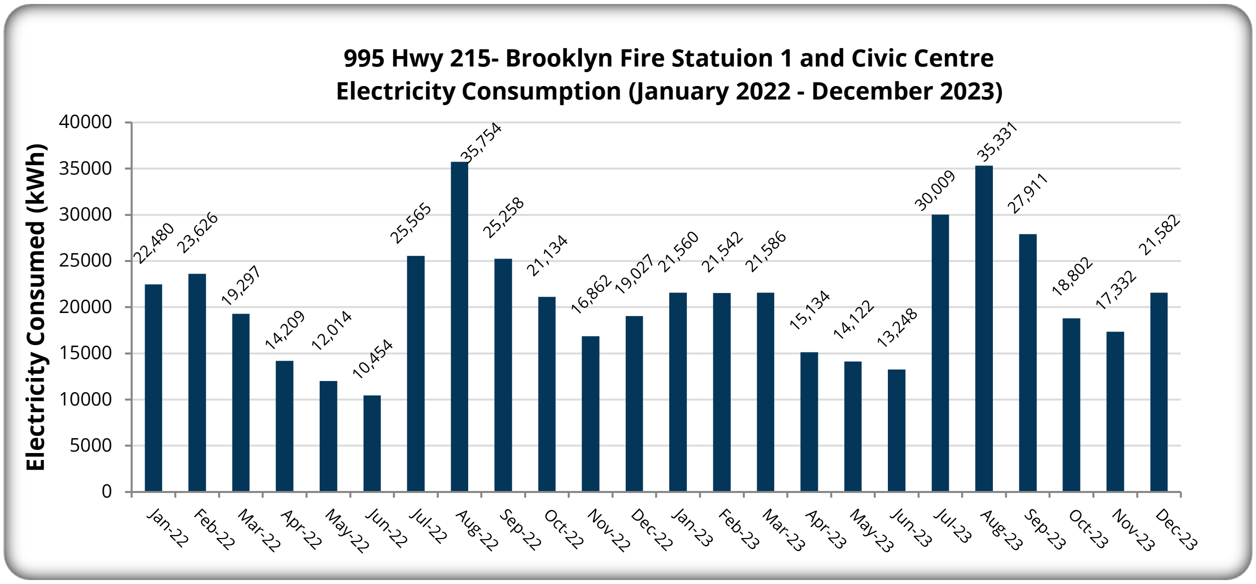

Figure 3.1: 2022/2023 Monthly Electricity Consumption

Figure 3.1 depicts a trend that shows a higher electricity consumption in the summer months, which is most likely due to the demand for air-conditioning in the building. Total electricity usage in the period January 2022/December 2022 was 245,680 kWh and 258,159 kWh in the January 2023/December 2023 year. The average annual energy consumption considering these two 12-month periods is 251,920 kWh.

Facility electricity demand was reviewed for each of the months between January 2022 and December 2023. Figure 3.2 presents a monthly peak demand trend for this 24-month period.

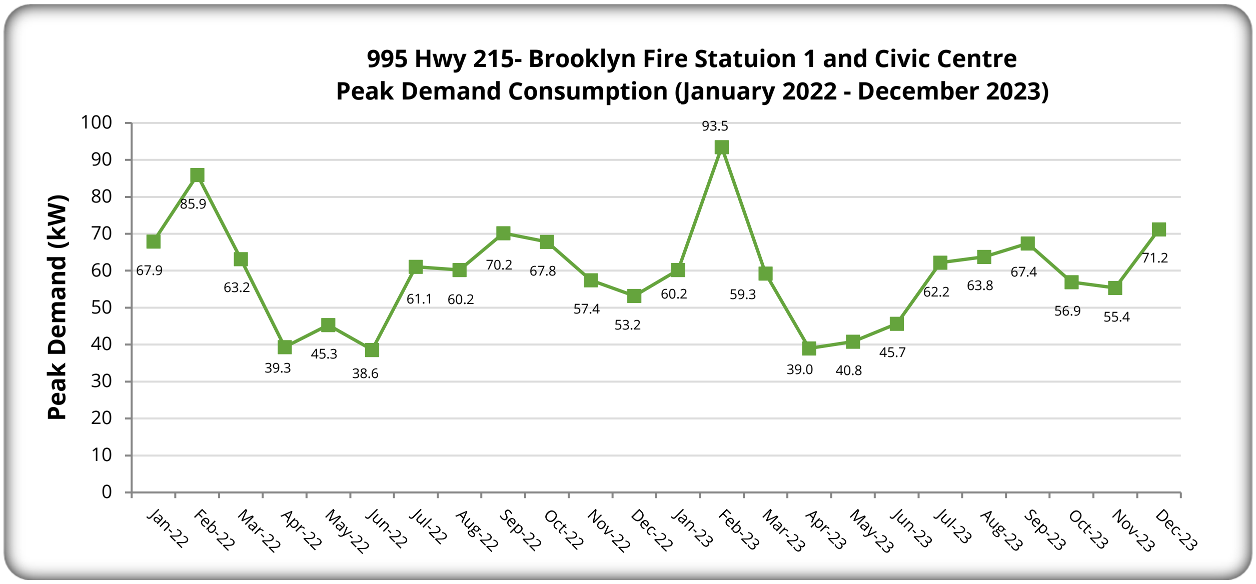

Figure 3.2: Monthly Electricity Peak Demand over 24 Consecutive Months

Figure 3.2 shows a trend that closely follows the kWh consumption. The higher peak demand occurred during the winter months, which coincides with the month exhibiting the highest demand for space heating. The monthly peak demand ranges between 38.6 kW and 93.5 kW. The highest demand peak was recorded at 93.5 kW in February 2023 while the lowest demand occurred in the month of June 2022 at only 38.6kW.

3.1.2 Electricity Cost

Electricity is provided by the Nova Scotia Power as a "Commercial General Tariff" electricity rate[14].

[14] Source: General Tariff| Nova Scotia Power (nspower.ca). Retrieved: 2024-07-22

GENERAL TARIFF

Availability

This tariff is applicable to electric power and energy where the annual consumption is 32,000 kWh or greater and for which no other rates are applicable.

For General tariff customers eligible for the Small General tariff the following conditions apply:

- Customers must make a written request to take service under the Small General tariff.
- Customers can switch rate classes twice in a 24-month period.
- After switching, customers shall take service under this tariff for a minimum of six months subject to meeting the load threshold criteria.

Demand Charge

$10.554 per month per kilowatt of maximum demand

Energy Charge

15.076 ¢ per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of maximum demand
11.779 ¢ per kilowatt hour for all additional kilowatt hours

Figure 3.3: NSPI Commercial General Tariff Rate

The electricity consumption cost breakdown is depicted in Figure 3.3. This shows that the kWh cost represents about 79% and 81% of the cost in the monthly power bills in 2022 and 2023, respectively. Monthly electricity cost closely follows the monthly kWh consumption. Total electricity cost in the period January 2022/December 2022 was $35,547 and $38,571 in the January 2023/December 2023 period. The average annual electricity cost considering this two 12-month period is $37,059. Also, the average unit cost of electricity, considering all costs in the bills, was $0.1471/kWh (not including HST) over the 24-month period provided.

An estimated electricity (kWh only) rate for 2024 of $0.1563/kWh was calculated by applying 2024 NSPI Commercial General Tariff rates to 2023 electricity consumption and peak demand values. A 15% HST was also applied. This average kWh rate does not include the additional demand charge, as the implementation of PV to the facility will not reduce the facility's peak demand.

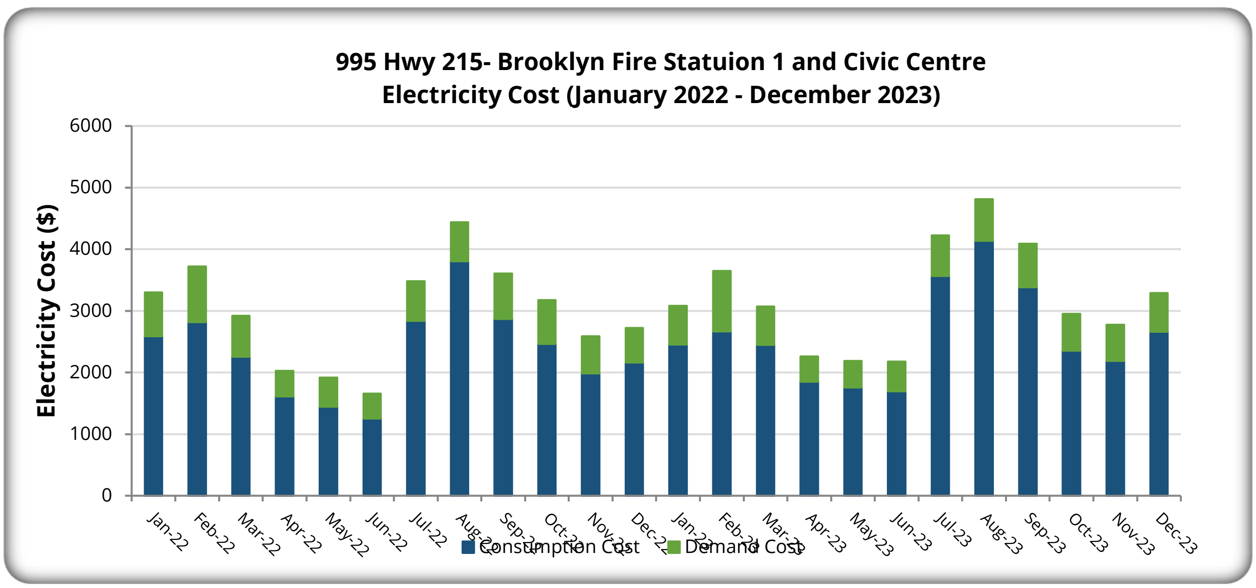

Figure 3.4: Electricity Cost Breakdown

Table 3.1 shows the monthly power bill cost breakdown for the January 2022 to December 2023 24-month period.

Table 3.1: Monthly Power Bill Cost Breakdown for the January 2022 to December 2023

Month-Year	Consumption (kWh)	Consumption Cost ($)	Peak Demand (kW)	Demand Cost ($)	Invoice Amount ($)
January 2022	22,480	$2,585.84	67.9	$712.75	$3,298.59
February 2022	23,626	$2,817.49	85.9	$901.69	$3,719.18
March 2022	19,297	$2,255.59	63.2	$663.41	$2,919.00
April 2022	14,209	$1,613.41	39.3	$412.53	$2,025.94
May 2022	12,014	$1,443.33	45.3	$475.51	$1,918.84
June 2022	10,454	$1,250.55	38.6	$405.18	$1,655.73
July 2022	25,565	$2,839.85	61.1	$641.37	$3,481.22
August 2022	35,754	$3,806.08	60.2	$631.92	$4,438.00
September 2022	25,258	$2,870.24	70.2	$736.89	$3,607.13
October 2022	21,134	$2,461.03	67.8	$711.70	$3,172.73
November 2022	16,862	$1,985.24	57.4	$602.53	$2,587.77
December 2022	19,027	$2,164.25	53.2	$558.44	$2,722.69
January 2023	21,560	$2,451.83	60.2	$631.92	$3,083.75
February 2023	21,542	$2,668.50	93.5	$981.47	$3,649.97
March 2023	21,586	$2,448.41	59.3	$622.47	$3,070.88
April 2023	15,134	$1,849.34	39.0	$411.61	$2,260.95
May 2023	14,122	$1,754.73	40.8	$430.60	$2,185.33
June 2023	13,248	$1,695.07	45.7	$482.32	$2,177.39
July 2023	30,009	$3,567.26	62.2	$656.46	$4,223.72
August 2023	35,331	$4,137.74	63.8	$673.35	$4,811.09
September 2023	27,911	$3,380.82	67.4	$711.34	$4,092.16
October 2023	18,802	$2,353.24	56.9	$600.52	$2,953.76
November 2023	17,332	$2,188.69	55.4	$584.69	$2,773.38
December 2023	21,582	$2,662.30	71.2	$627.07	$3,289.37

3.1.3 Total Energy Use Summary

The facility's total energy usage is shown in Table 3.2. The average for the 24-month period considers the electricity consumption records for January 2022 to December 2023.

Table 3.2: Energy Use Summary

Brooklyn Fire Station 1 and Civic Centre	2022	2023
Electricity		
Annual Electricity and Demand Cost ($)	$35,547	$38,572
Annual Electricity Consumption (kWh)	245,680	258,159

Brooklyn Fire Station 1 and Civic Centre	2022	2023
Annual Electricity Consumption (GJ)	884.4	929.4
Cost per GJ ($/GJ)	$40.19	$41.50
Percentage of Total Energy (%)	100.00%	100.00%
GHG Emissions (tCO_2/yr)	136.9	116.3
kWh Cost w/o Demand + HST to be used for Cost Savings Estimations ($/kWh)	$0.1563/kWh	

3.2 NSPI Net Metering Program

The Net Metering Program offered by NSPI provides an incentive for on-site renewable power generation. Using a 2-way meter, NSPI records the amount of power consumed by the facility, as well as any surplus power which is generated on-site using renewable technologies and returned to the grid. NSPI then charges the customer for the difference between energy consumed and energy returned to the grid.

NSPI allows the installation of PV systems of a minimum size of 27kW AC up to a maximum 1000kW AC array for net metering if the NSPI customer has a demand meter which this facility does. If the facility does not have a demand meter, or it is not a winery, farm, or licensed aquaculture plant, the facility could have a PV system with a capacity between 27 and 200 kW AC. If the facility owner has multiple accounts with NSPI, the PV system can supply electricity to other accounts owned by the same person/institution as long as they are within the same geographical area known as NSPI distribution zone.

Annual PV production cannot be higher than the building's annual electricity consumption to qualify for net metering[15].

3.3 Community Solar Program

The Community Solar Program offered by the province of Nova Scotia provides an incentive for the installation of 0.5MW AC up to a maximum 10MW AC[16]. The community solar PV system must be interconnected directly to NSPI's transmission system. The program is eligible to municipalities within the province. Participants of the program enter into a power purchase agreement with NSPI in which the client submits a proposed fixed-rate per kilowatt-hour generated, a minimum of $0.07/kWh, that is locked in for 25 years. The participant is also responsible for obtaining subscribers for the PV system, which must meet the criteria laid out by the Nova Scotia Community Solar Program, the guidelines of which are presented in Appendix A.

15 Source: Commercial Net Metering| Nova Scotia Power (nspower.ca). Retrieved: 2024-07-31
16 Source: Community Solar Program | Department of Energy and Mines (novascotia.ca). Retrieved: 2024-07-31

3.4 Considerations to Size the PV System

The Brooklyn Fire Station and Civic Centre consumes over 240,000 kWh/yr which makes it a good candidate for a solar PV system with a capacity of about 195 kW (AC). This is the maximum capacity allowed by NSPI for a client that wants to participate in the net metering program. A 195 kW (AC) PV array in Nova Scotia will produce, on average 240,000 kWh (AC) per year, which is about the building's annual consumption, thus making the building eligible for the net metering program. The net metering program will permit surplus energy generated from the array to be transferred to the NSPI grid via a bi-directional meter that will record the amount of energy transferred to the grid and credit that amount against future consumption from the grid. This system allows for all energy generated by the array to be used productively without the need or expense of an onsite energy storage system.

3.5 PV System

3.5.1 Ground Mounted

The ground mounted PV system can be located on the area west of the building. Water wells and any other infrastructure should be considered when sizing a solar PV array. A typical ground mounted system is shown in Figure 3.5. The implementation of this type of racking system will typically require a geotechnical analysis of the site to be able to design the array foundations. Also, a ballasted PV system can be implemented, which does not require foundations to anchor the racking to the ground. Site conditions are sufficiently typical to permit a standard foundation design for this size of array to be used for this level of analysis. The cost of geotechnical analysis, as part of the detailed system design cost, is included in the capital cost estimate for this array. Also, alternative mounts such as single or dual axis tracking were not considered due to the additional maintenance requirements.

Figure 3.5: Typical Ground Mounted PV Array

3.5.2 Roof Mounted

A PV system can be accommodated on the flat roof with a ballasted racking system. Panels could be placed in landscape position, oriented towards the south at an angle of 10°. Alternatively, a PV system can also be accommodated on a pitched roof, with the panels oriented on a southern roof face at an angle matching the roof slope. This measure should only be considered when the building roof is due for replacement or if it can be determined that the existing roofing system has at least 25 years of remaining life.

HVAC equipment and any other infrastructure should be considered when sizing a solar PV array. A typical roof mounted system is shown in Figure 3.6.

Figure 3.6: Typical Ballasted Roof Mounted PV Array

The implementation of a system of this type will require a structural assessment of the roof to determine if it can withstand the load from the PV panels. If the assessment determines that the roof structure cannot withstand the load, then the roof structure will need to be reinforced. The estimated implementation cost includes the cost for the structural assessment, but it does not include the cost for the roof reinforcement (this cost is determined or estimated after the completion of the structural assessment).

3.6 Incentive Programs

3.6.1 Low Carbon Communities Program

West Hants Regional Municipality may be eligible for the *Low Carbon Communities Program.* The program offers funding to recover up to 75% of the total project costs to a maximum of $75,000.The program provides 90% of the funding at the start of the project and the remaining 10% when the project is completed, and the final reports submitted. No more than 75% of the total project cost can be funded through the provincial government[17]. This program requires that reduction in GHG emissions be demonstrated. The expected reductions in capital cost for this project, due to this incentive program, are included in the financial analysis. Further details about the requirements from this program can be found here: Low Carbon Communities - Government of Nova Scotia, Canada. The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

3.6.2 Green Municipal Fund: Local Energy Generation

West Hants Regional Municipality may be eligible for the Green Municipal Fund's *Community Energy Systems: Capital Projects* grant and loan program. The program offers a combined grant and loan up to 80% of eligible project costs to a maximum of $10,000,000. With the grant being eligible for up to 15% of project costs. This program requires the

[17] Source: Low Carbon Communities - Government of Nova Scotia, Canada. Retrieved: 2024-07-31

completion of a feasibility study which considers technical and financial, as well as the social and environmental impacts of the project[18]. Further details about the requirements from this program can be found here: Capital project: Community Energy Systems (greenmunicipalfund.ca).

3.6.3 Sustainable Communities Challenge Fund

West Hants Regional Municipality may be eligible for the *Sustainable Communities Challenge Fund: Mitigation Stream*. This fund provides grants up to 80% of eligible projects costs to a maximum of $1,000,000. The applicant must supply a minimum of 20% of eligible project costs, which may be made by alternate funding sources such as federal funding sources. This program requires that reduction in GHG emissions be demonstrated[19]. Further details about the requirements from this program can be found here: Funding Opportunities - Sustainable Communities Challenge Fund (nschallengefund.ca). The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

3.6.4 Low Carbon Economy Challenge

West Hants Regional Municipality may be eligible for the *Low Carbon Economy*. This fund provides grants up to 50% of eligible projects costs for provincial municipalities. The fund ranges from a minimum of $1,000,000 to a maximum of $25,000,000 in available funding. According to the program, the project must produce electricity for the facility's own use. Eligible projects must result in a reduction in GHG emissions. Further details about the requirements from this program can be found here: Low Carbon Economy Challenge Applicant Guide 2023 - Canada.ca.[20] The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

3.7 Technical-Financial and Life Cycle Analyses

The sizing and estimation of energy production from the PV system was completed with the modelling software PVSyst, which is one of the most recognized PV modelling software platforms in the world. The PVSyst model considered the building's load profile or energy consumption, the exact location of the PV array, the site's weather data and solar radiation, estimated near and far shading issues, and estimated panel soiling issues.

This analysis included the installed cost of the PV system and, if applicable, financial incentives, and electrical upgrade cost. Additionally, this analysis considered the

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[18] Source: Capital project: Community Energy Systems (greenmunicipalfund.ca). Retrieved: 2024-07-31
[19] Source: Funding Opportunities - Sustainable Communities Challenge Fund (nschallengefund.ca). Retrieved: 2024-07-31
[20] Source: Low Carbon Economy Challenge - Canada.ca. Retrieved: 2024-07-31

degradation in power production over time from the PV modules, string inverter replacement cost after ten (10) to twelve (12) years of operation, inflation rate, annual maintenance cost, and discount rate, among other variables. Usually for string inverters, the replacement cost is about 10% of the PV system installed cost.

Four different PV system arrangements were assessed to determine which system shows the better financial performance, such as the lowest levelized cost of electricity and simple payback. Each system was evaluated considering standard panels (monofacial) and bi-facial panels. These options include:

1. **Option 1A:** 195 kWp DC, 188 kW AC PV system with monofacial panels. Net metering.
2. **Option 1B:** 178 kWp DC, 150 kW AC PV system with bifacial panels. Net metering.
3. **Option 2A:** 646 kWp DC, 563 kW AC PV system with monofacial panels. Community Solar.
4. **Option 2B:** 642 kWp DC, 563kW AC PV system with bifacial panels. Community Solar

3.7.1 Financial Assumptions

The following list includes all the assumptions and variables considered for the technical and financial analysis of both roof and ground mounted PV systems.

- Solar PV modules capacity: monofacial 555 W; bifacial 550 W
- Inverter: String inverter
- PV panel orientation and angle: due south at a 40° angle for ground mounted and 10° angle for rooftop ballasted systems, oriented slightly to the southeast
- Roof mounted arrays were considered as monofacial for all options.
- Building annual electricity consumption
- PV system modelled with software PVSyst
- General Inflation rate: 3%
- NSPI Electricity Inflation Rate: 4%
- O&M Inflation Rate: 4%
- Discount rate: 6.5%
- Interest rate: 6.5%
- Life of the project: 25 years
- Equity Ratio: 100% equity if capital <$150,000. If capital is >$150,000, consider $150,000 as equity and the rest as a loan, 20 year loan term if capital >$150,000.
- NS Power GHG emission intensity factor: 0.4506 CO_2e kg/kWh in 2023[21]
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr
- String inverter replacement cost in year 12 (10% of CAPEX)

[21] Source: https://www.nspower.ca/cleanandgreen/air-emissions-reporting. Retrieved: 2024-08-09

3.7.2 PV Systems Cost

Solar PV contractors in Nova Scotia were contacted to obtain budgetary installed costs for the proposed PV system arrangements, including Supernova Solar, Wattup Solar, and Natural Forces. It was determined that the average installed price for PV arrays with monofacial or standard panels is $2,175-3,000/kWp DC and with bifacial modules is $2,200-$3,075/kWp DC, depending on the system size, racking system, inverter technology (string versus microinverter), and PV installer. These budgetary installed costs do not include HST. This pricing excludes the costs for a geotechnical analysis and any required electrical upgrades and structural modifications to accommodate the new PV system.

3.7.3 Geotechnical Analysis and Cost

Foundation designs of solar photovoltaic (PV) arrays commonly consist of ballasted footings founded at the ground surface (i.e., precast concrete pads), or anchored footings consisting of shallow, driven pile, or helical screw pile foundations embedded below ground. PV arrays also include supporting infrastructure such as service roads, storage shipping containers, electrical substations with transformers, concrete pads for electrical equipment, battery storage systems, etc. that each have their own unique foundation requirements.

Geotechnical investigations in support of PV arrays commonly consist of either test pit or borehole drilling investigations. The decision to excavate test pits versus drill boreholes is determined based on site specific requirements and considerations. A desktop study and site visit can help better define the geotechnical field investigation requirements. Underground utility locating should be completed prior to conducting the field investigations.

Geotechnical reports will often be structured in the following way:

- Introduction
- Project and Site Description
- Fieldwork Procedure
- Summarized Subsurface Conditions
- Discussions and Recommendations (including earthworks, foundation design for PVs and associated infrastructure (i.e., bearing capacity and settlement), slope stability, trenching, service roads, construction monitoring, etc.)

In-situ and laboratory testing on soils is conducted to characterize various index, strength, and environmental properties of the soils. This testing may include:

- Standard penetration testing (SPT)
- Moisture content
- Grain size analysis
- Proctor density
- Unconfined compressive strength (UCS) of rock

- Basic chemical testing relating to corrosion of buried concrete and steel including pH, sulphate, and chloride
- Thermal conductivity
- In-situ electrical resistivity
- Other in-situ strength tests as required
- Other environmental quality tests as required

3.7.3.1 Site Description

The site is located at the Brooklyn Fire Station and Civic Centre, at 995 Highway 215, Brooklyn, NS. As seen in Figure 3.7 and Figure 3.8. Based on a review of satellite imagery, it appears that the area has been used as a dump site for fill materials for at least a decade or more. The exact composition and environmental soil quality of the fill is unknown. Around 2010, a large berm of material appears to have been constructed along the south end of the site. The PV arrays are proposed to be located across the entire site. Anchored foundations are proposed.

Based on geologic mapping, the principal soil unit in the area is ground moraine and streamlined drift till. The till is described as silty, compact, material derived from both local and distant sources[22].

Figure 3.7: Ortho - 995 Highway 215 - Anchored PV array (blue) (GoogleEarth, 2024)

[22] Stea, R.R., Conley, H., Brown, Y. (1992). Surficial Geology of the Province of Nova Scotia – Map 92-3.

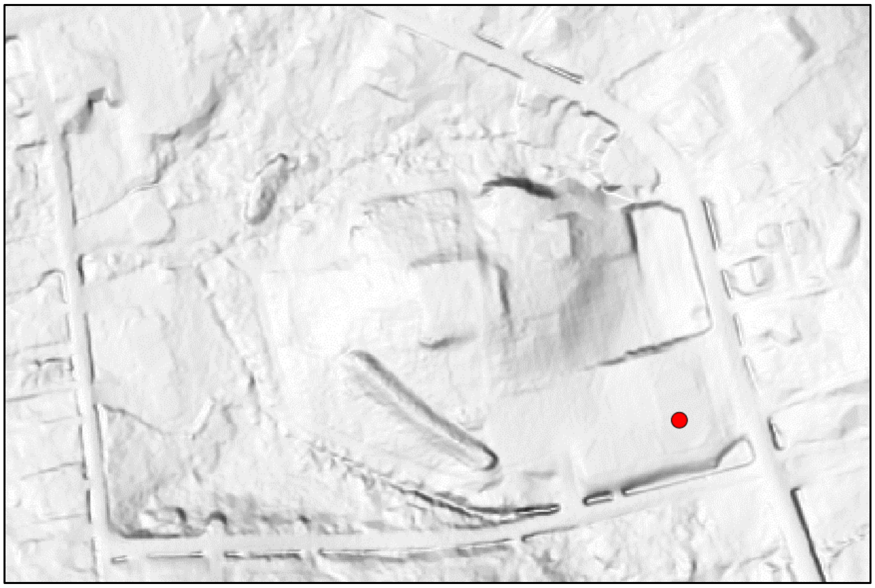

Figure 3.8: LiDAR - 995 Highway 215 (GeoNOVA, 2024)

3.7.3.2 Potential Geotechnical Challenges

Potential geotechnical challenges include:

- Unknown fill materials at the site.
- Unknown placement and compaction method for fill materials at the site.
- Unknown soil quality of fill materials at the site.
- Slope stability.
- Bearing capacity.
- Differential settlement fill materials (if ballasted foundations are selected).
- Frost heave of fill materials (if ballasted foundations are selected).
- Shallow foundations may not be feasible or cost effective due to potential thickness of fill materials being >1.5 m.
- Helical screw piles may not be feasible due to potential construction debris (i.e., concrete/rebar etc.).
- It is unknown if any capped soils are present (i.e., liner system).
- Misalignment of ballasted PVs due to settlement or frost heave (if ballasted foundations are selected).
- Influence of PVs on vegetative cover, erosion control, and stormwater management.

3.7.3.3 Suggested Geotechnical Study

To support the PV array foundation design, the following geotechnical study is suggested:

- Geotechnical borehole investigation.
- Approximately 9 boreholes drilled within the proposed development area.
- Approximately 3 monitoring wells to assist with groundwater level determination.
- Boreholes to be drilled through fill materials into competent native soils. Estimated depth is approximately 6-8 m.
- In-situ and laboratory testing and geotechnical report as described above in General Geotechnical Requirements.

3.7.3.4 Cost Estimate

The cost of the proposed geotechnical investigation would be in the range of $25k - $35k. Environmental testing, if required, could be extra.

3.7.4 Electrical Analysis and Cost

There are two options we are considering for this location – a net metering arrangement (188kW-AC), and a larger system that would be eligible for the Community Solar Program (563kW-AC). This location is primarily powered by a three-phase 208V distribution system.

Option 1 – Net Metering

In this option, the PV system size is restricted to the present energy consumption of the site. Therefore, no upgrade to the service entrance is required. A means of interconnecting the inverters with the existing distribution system will be required.

A system at 188kW would export 521.8A, so the system is oversized for a panelboard connection. The large panelboards on site are 200A.

There is a splitter presently fed from the transfer switch, with a lamicoid nameplate rating of 600A. This equipment will also not be suitable. A replacement splitter, rated 1200A, should be installed to handle the full output of the PV system and service entrance.

Per NSPI Bulletin B-64-200, a control system will be required to ensure the PV system shuts down upon loss of the utility interconnection.

Table 3.3: Option 1 – Net Metering Electrical Work Cost Estimates

Item	Estimated Cost	Notes
Interconnection Wiring	$3,000	
1200A Splitter, NEMA 1	$3,000	
1 x 200kVA	$25,000	This may not be required if 208V inverters can be obtained.
2 x 600A Disconnect Switches, Complete with 600A Fuses	$6,000	
ATS Provisions	$1,500	
Total	**$37,000 (if 480V inverters are used) $12,000 (if 208V inverter are used)**	N/A

Option 2 – Community Solar

This system is planned to be 563kW-AC, so the considerations in the previous section with respect to current rating, applies. Since this is so much larger, a separate utility interconnection is more practical. This would mean the installation of an Owner-supplied step-up transformer to interconnect with the 24.4kV distribution system would be required. Given equipment availability, 480V is the practical low voltage option.

Table 3.4: Option 2 – Community Solar Electrical Work Cost Estimates

Item	Estimated Cost	Notes
Overhead Line Upgrades	$6,560	Line upgrades are estimated at $85/m. NSPI may provide the first 92m, reducing this cost to $0.
NSPI Interconnection Equipment	$50,000	NSPI will require the IPP to pay for the protective devices required to interconnect the site.
1 x 750kVA Padmount Transformer	$70,000	
Primary Interconnection Equipment	$35,000	
1 x 1000A 480V Switchboard	$60,000	
Total	**$221,560**	N/A

3.7.5 Structural Upgrade Cost

A review of the as-built drawings, dated 2009, indicates that the roof structure in the area of the proposed PV array is steel deck and open web steel joists, supported on steel framing with conventional concrete foundation walls and footings, or concrete sandwich panels at exterior walls with insulated concrete form foundation walls and footings. The general construction was confirmed during the July 2024 site visit. The drawings also provided design loads for the roof structure including suspended dead load, snow load, and wind uplift.

A review of the original dead load, in comparison with the weight of the ballasted PV array, indicates that the overall design load would be increased in the order of 6%, which is acceptable for this type of structure.

The National Building Code for Canada (NBCC) 2020, which will be adopted by the Province of Nova Scotia soon, has new design considerations addressing the accumulation of snow drifts around PV systems. For flat roofs with tilted solar panels, snow drifts will accumulate if the top height of the panels is greater than the base snow depth on the roof. If it is determined that snow drifts will accumulate, this is additional load on the roof, and the structure would need to be reinforced. It is important to note that the design snow load for this building has increased from the code used in the original design of the building to NBCC 2020. If the snow loading distribution on the roof were to change (i.e., the creation of new snow drifts), the entire building would need to be analyzed with loads prescribed by the current code and will potentially require reinforcing. It is recommended that the PV panels be installed in such a way as to avoid the creation of snow drifts and, therefore, most likely avoid any reinforcing requirements.

The use of a ballasted array system does not require connection to the existing structure, therefore, there are no anticipated structural costs.

3.7.6 Option 1 PV System – Net Metering

This PV system was sized considering that all the energy produced has to be consumed onsite and no surplus energy can be exported to the grid. This system would be equipped with a power production control system to monitor the building load to adapt the PV system production and to make sure there is no surplus energy returned to the grid. The assumptions and variables considered for the financial analysis for Option 1 are the same for Option 2.

Figure 3.9 shows the 3D models in PVSyst and the area considered for the implementation of the PV system considering monofacial (Option 1A) and bifacial panels (Option 1B).. The following items were considered when placing the PV system on this part of the property:

- No shading issues due to the proximity to nearby taller structures.
- Relatively flat surface.
- Proximity to the main building, which facilitates their interconnection.
- Excellent exposure to due south.
- Excellent visibility for the facility operators and the public.
- Easy access for maintenance.
- Racking system will be anchored to the ground.

Figure 3.9: Ground Mounted PV Array – Option 1A and 1B

The estimated energy generation from the PVSyst model, as well as the estimated installed cost, current electricity rate, building annual energy consumption, and PV system specific production is included in Table 3.5. The PVSyst reports are included in Appendix B. Costs in the table below include HST.

Table 3.5: Ground Mounted PV System – Options 1A and 1B

Brooklyn Fire Station – Option 1 Net Metering	Option 1A – 195 kWp DC	Option 1B – 178 kWp DC Bifacial
Ground Mount PV Capacity (kWp DC)	195.0	178.0
Ground Mount PV Capacity (kWp AC)	188.0	150.0
Ground Mount Installed Cost ($/kWp)	$3,073	$3,119
Ground Mount Cost [PV only] ($)	$599,235	$555,182
Electricity Rate ($/kWh)	$0.1563	$0.1563
Annual Consumption (kWh/yr)	251,919	251,919
Generated by PV and Consumed on Site (kWh/yr)	89,791	93,072
Generated by PV and Exported to Grid (kWh/yr)	162,128	154,499
PV Generation (kWh/yr)	251,919	247,571
PV Specific Production (kWh/yr/kWp)	1,292	1,391

When comparing the results for Option 1 considering monofacial panels (Option 1A) and bifacial panels (Option 1B), the following was observed:

- The installed cost per kWp for bifacial panels is less than 1.5% higher than for monofacial panels.
- All electricity generated by the PV system would be either consumed on site or net metered to the grid.
- Surplus energy is not generated with the considered building energy consumption.
- Option 1A would provide 100% of the annual energy consumption.
- Option 1B would provide 98.3% of the annual energy consumption.
- All energy produced onsite will generate a cost savings at the same rate (NSPI electricity rate).
- The production and specific production from Option 1B (bifacial) is 1.7% lower and 7.7% higher than from Option 1A, respectively, even though Option 1A kWp DC installed capacity is 8.7% larger than Option 1B.

In addition to these PV costs, other costs should be considered in the financial analysis. Table 3.6 shows the PV installation cost, as well as the electrical upgrade cost, fencing, geotechnical analysis, and design cost. As expected, the highest installation cost is for Option 1A, which also results in the highest total cost.

Table 3.6: PV Cost and Additional Costs - Options 1A and 1B

Installed Cost	Option 1A – 195 kWp DC Monofacial	Option 1B - 178 kWp DC Bifacial
PV Ground Mounted ($)	$599,235	$555,182
Geotechnical Analysis Cost ($)	$35,000	$35,000
Electrical Upgrade Cost ($)	$37,000	$37,000
Site Fencing ($)	$35,000	$35,000
Design ($)	$51,000	$51,000
Total Project Cost ($)	**$757,235**	**$713,182**

Considering all these costs and the total savings, the following tables show the simple payback, net present value for a 25-year project horizon, life cycle costs (LCC), and the CO_2 emission reductions. Total savings include the energy savings and annual maintenance cost. Maintenance cost includes cleaning the panels twice a year, tightening the mechanical and electrical connections once a year, spot measurements once a year, and remote review of the system performance every three or four months. Electrical upgrade cost estimates are assuming a 480V inverter is used.

Table 3.7: Financial Analysis – Options 1A and 1B

Fire Station Option 1	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option 1A - 195 kWp DC	$757,235	$36,379	$39,375	20.8	-$53,150	0.9	40.5
Option 1B - 178 kWp DC	$713,182	$35,919	$38,695	19.9	-$15,838	1.8	41.9

Option 1A results in higher savings, but the Option 1B installation cost is lower, which results in a shorter simple payback period for Option 1B. The simple payback considers inflation, power production degradation, maintenance cost, and equipment replacement cost for a 25-year period. The cash flow and LCOE for both projects should be reviewed to further assess these options. The cash flow includes the maintenance cost and the savings from the generated electricity. Typically, a PV system fitted with string inverters requires the replacement of the inverters after ten (10) to twelve (12) years of operation, which results in a high maintenance cost in year 11 or 12.

3.7.6.1 Levelized Cost of Energy (LCOE)

The LCOE measures lifetime costs divided by energy production. It calculates the present value of the total cost of implementing and operating the building over an assumed lifetime. LCOE allows the comparison of different PV projects and different technologies (e.g., wind, solar, natural gas) of unequal life spans, project size, different capital cost, risk, return, and capacities. Figure 3.10 shows the LCOE formula.[23]

The LCOE calculation for this project considered the following variables:

- O&M Inflation rate: 4%
- Discount rate: 6.5%
- Life of the project: 25 years
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr (the same as in the previous section).
- Inverter replacement cost in year 12 (10% of CAPEX).

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

I_t = Investment expenditures in year t (including financing)
M_t = Operations and maintenance expenditures in year t
F_t = Fuel expenditures in year t
E_t = Electricity generation in year t
r = Discount rate
n = Life of the system

Figure 3.10: LCOE Formula

Table 3.8 shows the costs included in the calculation of the LCOE and the estimated annual energy production factoring power production depreciation. The LCOE for Option 1A was determined to be $0.4513/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE of the purchase of electricity from the grid is $0.2273/kWh, which is lower than the LCOE for the PV system.

Table 3.8: LCOE Calculation – Option 1A

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000		-	-
1	-	$54,471	-$2,996	251,919
2	-	$54,471	-$3,116	249,400
3	-	$54,471	-$3,241	248,153
4	-	$54,471	-$3,370	246,912
5	-	$54,471	-$3,505	245,677
6	-	$54,471	-$3,645	244,449
7	-	$54,471	-$3,791	243,227
8	-	$54,471	-$3,943	242,011
9	-	$54,471	-$4,100	240,801
10	-	$54,471	-$4,264	239,597
11	-	$54,471	-$4,435	238,399
12	-	$54,471	-$64,536	237,207

[23] Source: https://www.energy.gov/sites/prod/files/2015/08/f2/LCOE.pdf. Retrieved: 2020-02-05

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
13	-	$54,471	-$4,797	236,021
14	-	$54,471	-$4,989	234,841
15	-	$54,471	-$5,188	233,666
16	-	$54,471	-$5,396	232,498
17	-	$54,471	-$5,612	231,336
18	-	$54,471	-$5,836	230,179
19	-	$54,471	-$6,070	229,028
20	-	$54,471	-$6,312	227,883
21	-		-$6,565	226,743
22	-		-$6,828	225,610
23	-		-$7,101	224,482
24	-		-$7,385	223,359
25	-		-$7,680	222,242

The LCOE for Option 1B was determined to be $0.4297kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE of the purchase of electricity from the grid is $0.2273/kWh, which is lower than the LCOE for the PV system. The LCOE for the NSPI grid was calculated considering inflation rate and the annual energy consumption of the building.

Table 3.9: LCOE Calculation – Option 1B

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000	-	-	-
1	-	$48,277	-$2,776	247,571
2	-	$48,277	-$2,887	245,095
3	-	$48,277	-$3,002	243,870
4	-	$48,277	-$3,123	242,650
5	-	$48,277	-$3,247	241,437
6	-	$48,277	-$3,377	240,230
7	-	$48,277	-$3,512	239,029
8	-	$48,277	-$3,653	237,834
9	-	$48,277	-$3,799	236,645
10	-	$48,277	-$3,951	235,461
11	-	$48,277	-$4,109	234,284
12	-	$48,277	-$59,792	233,113
13	-	$48,277	-$4,444	231,947
14	-	$48,277	-$4,622	230,787
15	-	$48,277	-$4,807	229,633

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
16	-	$48,277	-$4,999	228,485
17	-	$48,277	-$5,199	227,343
18	-	$48,277	-$5,407	226,206
19	-	$48,277	-$5,623	225,075
20	-	$48,277	-$5,848	223,950
21	-		-$6,082	222,830
22	-		-$6,326	221,716
23	-		-$6,579	220,607
24	-		-$6,842	219,504
25	-		-$7,116	218,407

Table 3.10 summarizes the results of the financial assessment for both options. Option 1B shows the highest NPV and lower LCOE compared to Option 1A.

Table 3.10: Summary - Financial Analysis - Options 1A and 1B

Fire Station Option 1	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	LCOE $/kWh	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option 1A - 195 kWp DC Monofacial	$757,235	$36,379	$0.4513	20.8	-$53,150	0.9	40.5
Option 1B - 178 kWp DC Bifacial	$713,182	$35,919	$0.4297	19.9	-$15,838	1.8	41.9

Considering that Option 1B was shown to have the highest NPV and lower LCOE compared to Option 1A, a sensitivity analysis around the total implementation cost was performed. Table 3.11 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

3.7.6.2 Sensitivity Analysis – CAPEX

A sensitivity analysis around the total implementation cost of Option1B was performed. Table 3.11 shows what the simple and LCOE range would be if the total cost varied between -20% and 30%.

Table 3.11: CAPEX Sensitivity Analysis

PV System	CAPEX Variance +/-%	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	LCOE ($/kWh)	Utility LCOE ($/kWh)
Option 1B - 178 kWp DC Bifacial	0%	$713,182	$35,919	$38,695	19.9	-$15,838	1.8	$0.4297	$0.2273
	30%	$927,137			25.8	-$250,469	-3.6	$0.5710	$0.2273
	-20%	$570,546			15.9	$140,582	6.2	$0.3355	$0.2273

3.7.6.3 Sensitivity Analysis – Energy Generation

A sensitivity analysis around the total energy generation was performed. Table 3.12 shows what the simple payback and LCOE range would be if the electricity generation varied between -5% and +5%.

Table 3.12: Sensitivity Around kW/yr Generation

PV System	+/- % kWh/yr	kWh/yr	Total Savings ($/yr)	Simple Payback (yr)	LCOE $/kWh	Utility LCOE ($/kWh)
Option 1B - 178 kWp DC Bifacial	-	247,571	$35,919	19.9	$0.4297	$0.2273
	-5%	235,192	$33,985	21.0	$0.4523	$0.2273
	5%	259,950	$37,854	18.8	$0.4092	$0.2273

3.7.7 Option 2 PV System – Community Solar

This PV system was sized considering that all energy produced will be exported to the grid. The assumptions and variables considered for the financial analysis for Option 1 are the same for Option 2.

Figure 3.11 shows the 3D models in PVSyst and the area considered for the implementation of the PV system considering monofacial (Option 2A) and bifacial panels (Option 2B). The following items were considered when placing the PV system on this part of the property:

- No shading issues due to the proximity to nearby taller structures.
- Relatively flat surface.
- Proximity to the main building, which facilitates their interconnection.
- Excellent exposure to due south.
- Excellent visibility for the facility operators and the public.
- Easy access for maintenance.
- Ballasted PV system on the fire station flat roof.
- Racking system will be anchored to the ground for ground mounted array.

Figure 3.11: Ground Mounted PV Array – Option 2A and 2B

The estimated energy generation from the PVSyst model, as well as the estimated installed cost, current electricity rate, building annual energy consumption, and PV system specific production is included in Table 3.13. The PVSyst reports are included in Appendix B. Costs in the table below include HST.

Table 3.13: Ground Mounted PV System – Options 2A and 2B

Brooklyn Fire Station – Option 2 Community Solar	Option 2A - 646 kWp DC Monofacial	Option 2B – 642 kWp DC Bifacial
Roof Mount PV Capacity (kWp DC)	140.0	140.0
Roof Mount PV Capacity (kWp AC)	125.0	125.0
Roof Mount Installed Cost ($/kWp)	$2,801	$2,801
Roof Mount Cost [PV only] ($)	$392,140	$392,140
Ground Mount PV Capacity (kWp DC)	506.0	502.0
Ground Mount PV Capacity (kWp AC)	438.0	438.0
Ground Mount Installed Cost ($/kWp)	$2,813	$2,853
Ground Mount Cost [PV only] ($)	$1,423,378	$1,432,206
Total PV Capacity (kWp DC)	646.0	642.0
Total PV Capacity (kWp AC)	563.0	563.0
Total cost [PV only] ($)	$1,815,518	$1,824,346
Average Install Cost ($/kWh)	$2,810	$2,842
Power Purchase Electricity Rate ($/kWh)	$0.12	$0.12
Annual Consumption (kWh/yr)	-	-
Generated by PV and Consumed on Site (kWh/yr)	-	-
Generated by PV and Exported to Grid (kWh/yr)	816,942	860,961
PV Generation (kWh/yr)	816,942	860,961
PV Specific Production (kWh/yr/kWp)	1,265	1,341

When comparing the results for Option 2 considering monofacial panels (Option 2A) and bifacial panels (Optional 2B), the following was observed:

- The installed cost per kWp for bifacial panels is approximately 1.5% higher than for monofacial panels.
- All electricity generated by the PV system will be exported in a power purchase agreement.
- All energy produced onsite will generate revenue at the PPA rate (estimated -power Purchase agreement rate of $0.12/kWh).
- The production and specific production from Option 2B (bifacial) is 5.4% and 6% higher than from Option 2A, respectively, even though Option 2B kWp DC installed capacity is 0.6% smaller than Option 2A.

In addition to these PV costs, other costs should be considered in the financial analysis. Table 3.14 shows the PV installation cost, as well as the electrical upgrade cost, geotechnical analysis, and design cost. As expected, the highest installation cost is for Option 2B, which also results in the highest total cost.

Table 3.14: PV Cost and Additional Costs - Options 2A and 2B

Installed Cost	Option 2A – 646 kWp DC	Option 2B – 642 kWp DC Bifacial
PV Ground Mounted ($)	$1,423,378	$1,432,206
Geotechnical Analysis Cost ($)	$35,000	$35,000
Electrical Upgrade Cost ($)	$221,560	$221,560
Site Fencing ($)	$60,000	$60,000
Design ($)	$87,150	$87,150
Total Project Cost ($)	**$1,827,088**	**$1,835,916**

Considering all these costs and the total savings, the following tables show the simple payback, net present value for a 25-year project horizon, life cycle costs (LCC), and the CO_2 emission reductions. Total savings include the energy savings and annual maintenance cost. Maintenance cost includes cleaning the panels twice a year, tightening the mechanical and electrical connections once a year, spot measurements once a year, and remote review of the system performance every three or four months.

Table 3.15: Financial Analysis – Options 2A and 2B

Fire Station Option 2	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option 2A - 646 kWp DC Monofacial	$1,827,088	$88,955	$98,033	20.5	-$1,176,685	-	86.1
Option 2B - 642 kWp DC Bifacial	$1,835,916	$94,194	$103,315	19.5	-$1,122,548	-	87.2

Option 2A has a lower installation cost, but Option 2B results in higher savings, which results in a lower simple payback for Option 2B. The cash flow and LCOE for both projects should be reviewed to further assess these options. The cash flow includes the maintenance cost and the savings from the generated electricity. Typically, a PV system fitted with string inverters requires the replacement of the inverters after ten (10) to twelve (12) years of operation, which results in a high maintenance cost in year 11 or 12.

3.7.7.1 Levelized Cost of Energy (LCOE)

The LCOE measures lifetime costs divided by energy production. It calculates the present value of the total cost of implementing and operating the building over an assumed lifetime. LCOE allows the comparison of different PV projects and different technologies (e.g., wind, solar, natural gas) of unequal life spans, project size, different capital cost, risk, return, and capacities. Figure 3.12 shows the LCOE formula.[24]

The LCOE calculation for this project considered the following variables:

- O&M Inflation rate: 4%
- Discount rate: 6.5%
- Life of the project: 25 years
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr (the same as in the previous section).
- Inverter replacement cost in year 12 (10% of CAPEX).

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

I_t = Investment expenditures in year t (including financing)
M_t = Operations and maintenance expenditures in year t
F_t = Fuel expenditures in year t
E_t = Electricity generation in year t
r = Discount rate
n = Life of the system

Figure 3.12: LCOE Formula

[24] Source: https://www.energy.gov/sites/prod/files/2015/08/f2/LCOE.pdf. Retrieved: 2020-02-05

Table 3.16 shows the costs included in the calculation of the LCOE and the estimated annual energy production factoring power production depreciation. The LCOE for Option 2A was determined to be $0.4329/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system.

Table 3.16: LCOE Calculation – Option 2A

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000		-	-
1	-	$185,618	-$9,078	816,942
2	-	$185,618	-$9,441	808,773
3	-	$185,618	-$9,818	804,729
4	-	$185,618	-$10,211	800,705
5	-	$185,618	-$10,619	796,702
6	-	$185,618	-$11,044	792,718
7	-	$185,618	-$11,486	788,754
8	-	$185,618	-$11,945	784,811
9	-	$185,618	-$12,423	780,887
10	-	$185,618	-$12,920	776,982
11	-	$185,618	-$13,437	773,097
12	-	$185,618	-$195,526	769,232
13	-	$185,618	-$14,534	765,386
14	-	$185,618	-$15,115	761,559
15	-	$185,618	-$15,719	757,751
16	-	$185,618	-$16,348	753,962
17	-	$185,618	-$17,002	750,192
18	-	$185,618	-$17,682	746,441
19	-	$185,618	-$18,390	742,709
20	-	$185,618	-$19,125	738,996
21	-		-$19,890	735,301
22	-		-$20,686	731,624
23	-		-$21,513	727,966
24	-		-$22,374	724,326
25	-		-$23,269	720,705

The LCOE for Option 2B was determined to be $0.4125/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system.

Table 3.17: LCOE Calculation – Option 2B

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000		-	-
1	-	$186,410	-$9,122	860,961
2	-	$186,410	-$9,487	852,351
3	-	$186,410	-$9,866	848,090
4	-	$186,410	-$10,261	843,849
5	-	$186,410	-$10,671	839,630
6	-	$186,410	-$11,098	835,432
7	-	$186,410	-$11,542	831,255
8	-	$186,410	-$12,004	827,098
9	-	$186,410	-$12,484	822,963
10	-	$186,410	-$12,983	818,848
11	-	$186,410	-$13,502	814,754
12	-	$186,410	-$196,477	810,680
13	-	$186,410	-$14,604	806,627
14	-	$186,410	-$15,188	802,594
15	-	$186,410	-$15,796	798,581
16	-	$186,410	-$16,428	794,588
17	-	$186,410	-$17,085	790,615
18	-	$186,410	-$17,768	786,662
19	-	$186,410	-$18,479	782,728
20	-	$186,410	-$19,218	778,815
21	-		-$19,987	774,921
22	-		-$20,786	771,046
23	-		-$21,618	767,191
24	-		-$22,482	763,355
25	-		-$23,382	759,538

Table 3.18 summarizes the results of the financial assessment for both options. Option 2B shows the highest NPV and lower LCOE compared to Option 2A.

Table 3.18: Summary - Financial Analysis - Options 2A and 2B

Fire Station Option 2	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	LCOE $/kWh	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option 2A - 646 kWp DC Monofacial	$1,827,088	$88,955	$0.4329	20.5	-$1,176,685	-	86.1

Fire Station Option 2	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	LCOE $/kWh	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option 2B - 642 kWp DC Bifacial	$1,835,916	$94,194	$0.4125	19.5	-$1,122,548	-	87.2

Considering that Option 2B was shown to have the highest NPV and lower LCOE compared to Option 2A, a sensitivity analysis around the total implementation cost was performed. Table 3.19 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

3.7.7.2 Sensitivity Analysis – CAPEX

A sensitivity analysis around the total implementation cost was performed. Table 3.19 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

Table 3.19: CAPEX Sensitivity Analysis

PV System	CAPEX Variance +/-%	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	LCOE ($/kWh)	Utility LCOE ($/kWh)
Option 2B - 642 kWp DC Bifacial	0%	$1,835,916	$94,194	$103,315	19.5	-$1,122,548	-	$0.4125	$0.1745
	30%	$2,386,691			25.3	-$1,858,552	-	$0.5398	$0.1745
	-20%	$1,468,733			15.6	-$631,879	-	$0.3276	$0.1745

3.7.7.3 Sensitivity Analysis – Energy Generation

A sensitivity analysis around the total energy generation was performed. Table 3.20 shows what the simple payback and LCOE range would be if the electricity generation varied between -5% and +5%.

Table 3.20: Sensitivity Around kW/yr Generation

PV System	+/- % kWh/yr	kWh/yr	Total Savings ($/yr)	Simple Payback (yr)	LCOE $/kWh	Utility LCOE ($/kWh)
Option 2B - 642kWp DC Bifacial	-	860,961	$94,194	19.5	$0.4125	$0.1745
	-5%	817,913	$89,028	20.6	$0.4342	$0.1745
	5%	904,009	$99,359	18.5	$0.3929	$0.1745

3.7.7.4 Sensitivity Analysis – Power Purchase Rates

A sensitivity analysis around the power purchase rate was performed. Table 3.21 shows what the simple payback, savings and NPV range would be if the power purchase rate varied between -20% and +20%.

Table 3.21: Sensitivity Around Power Purchase Rate ($/kWh)

PV System	+/- % ($kWh/yr)	PPA Rate (kWh/yr)	Total Savings ($/yr)	Simple Payback (yr)	NPV ($)
Option 2B - 3203 kWp DC Bifacial	-	$0.1200	$485,891	19.4	-$1,122,548
	-20%	$0.0960	$380,039	22.8	-$1,373,038
	20%	$0.1440	$591,743	14.7	-$872,057

3.8 PV Project Estimated Timeline

The implementation of any of these projects will require the completion of a number of tasks. Considering that an engineering company produces the design and tender package, and a solar PV contractor installs the system (turn-key project), a project timeline was estimated. The tables below depict the estimated timeline to complete the options described for this site.

Table 3.22: Estimated Timeline for Option 1A and 1B

Task #	Option 1A and 1B- Tasks - 195 kWp and 178 kWp PV Systems-Net metering	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
1	RFP process to design and create the tender package for the PV system. Select PV designer. If WHRM requires an Engineer to act as Owner's Engineer, an RFP to select it could occur in parallel to the RFP to select the PV designer.	6	6	weeks after RFP was issued
2	PV Designer: Kick-off Meeting, Available Information Review	1	7	weeks after RFP was issued
3	PV Designer: Site Visit	1	8	weeks after RFP was issued
4	PV Designer: PV System Design and Tender Package Preparation	8	16	weeks after RFP was issued
5	WHRM: Design and Tender Package Review	1	17	weeks after RFP was issued
6	PV Designer: Design and Tender Package Update According to WHRM Comments	1	18	weeks after RFP was issued

Task #	Option 1A and 1B- Tasks - 195 kWp and 178 kWp PV Systems-Net metering	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
7	WHRM: Tender Package Is Issued	1	19	weeks after RFP was issued
8	Bidders: Tender Period, Question and Answer Period. Bids are submitted to WHRM.	4	23	weeks after RFP was issued
9	WHRM or Owner's engineer: Bid Assessment, Question and Answer with bidders, Bids Ranking and Recommendation. Successful bidder is contacted.	3	26	weeks after RFP was issued
10	WHRM: Negotiation with Successful Bidder. Contract signing.	2	28	weeks after RFP was issued
11	PV Contractor: Kick-off Meeting, Available Information Review, Site Visit.	2	30	weeks after RFP was issued
12	PV Contractor: Equipment Selection and Acquisition. PV System Installation.	14	44	weeks after RFP was issued
13	WHRM or Owner's Engineer: Design drawings and Shop Drawings Review. Site visits. Communications with PV Contractor (in parallel to above)	14	44	weeks after RFP was issued
14	PV Contractor: System Start-up	1	45	weeks after RFP was issued
15	WHRM or Owner's Engineer: As-built Document and Drawings Review. System Commissioning. Commissioning Report.	4	49	weeks after RFP was issued

Table 3.23: Estimated Timeline for Option 2

Task #	Option 2A and 2B – 646 kWp and 642 kWp PV Systems-Community Solar	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
1	RFP process to design and create the tender package for the PV system. Select PV designer. If WHRM requires an Engineer to act as Owner's Engineer, an RFP to select it could occur in parallel to the RFP to select the PV designer.	6	6	weeks after RFP was issued
2	PV Designer: Kick-off Meeting, Available Information Review	1	7	weeks after RFP was issued
3	PV Designer: Site Visit	1	8	weeks after RFP was issued

Task #	Option 2A and 2B – 646 kWp and 642 kWp PV Systems-Community Solar	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
4	PV Designer: PV System Design and Tender Package Preparation	8	16	weeks after RFP was issued
5	WHRM: Design and Tender Package Review	1	17	weeks after RFP was issued
6	PV Designer: Design and Tender Package Update According to WHRM Comments	1	18	weeks after RFP was issued
7	WHRM: Tender Package Is Issued	1	19	weeks after RFP was issued
8	Bidders: Tender Period, Question and Answer Period. Bids are submitted to WHRM.	4	23	weeks after RFP was issued
9	WHRM or Owner's engineer: Bid Assessment, Question and Answer with bidders, Bids Ranking and Recommendation. Successful bidder is contacted.	3	26	weeks after RFP was issued
10	WHRM: Negotiation with Successful Bidder. Contract signing.	2	28	weeks after RFP was issued
11	PV Contractor: Kick-off Meeting, Available Information Review, Site Visit.	2	30	weeks after RFP was issued
12	PV Contractor: Equipment selection and Acquisition. PV System Installation.	20	50	weeks after RFP was issued
13	WHRM or Owner's Engineer: Design drawings and Shop Drawings Review. Site visits. Communications with PV Contractor (in parallel to above)	20	50	weeks after RFP was issued
14	PV Contractor: System Start-up	1	51	weeks after RFP was issued
15	WHRM or Owner's Engineer: As-built Document and Drawings Review. System Commissioning. Commissioning Report.	4	55	weeks after RFP was issued

4 293 Wentworth Road – Windsor Wastewater Treatment Plant "New Lagoons"

4.1 Review of Historic Energy Performance

The Windsor Wastewater Treatment Plant "New Lagoons" located at 293 Wentworth Road in Windsor, NS, provided electricity bills for a 24-month period spanning January 2022 to December 2023. Energy consumption and demand were reviewed in annual terms to ensure that variation in seasonality was observable. With at least two periods available, a month-to-month comparison of the facility's energy performance was made from one year to the next. Review of electricity consumption profiles based on the information obtained from the two periods was discussed and is compared in this section. This review will also include observed variations in electricity demand by month across the two annual periods.

4.1.1 Electricity Use Profiles

Figure 4.1 provides the monthly electricity usage profile which shows the 24-month period from January 2022 to December 2023.

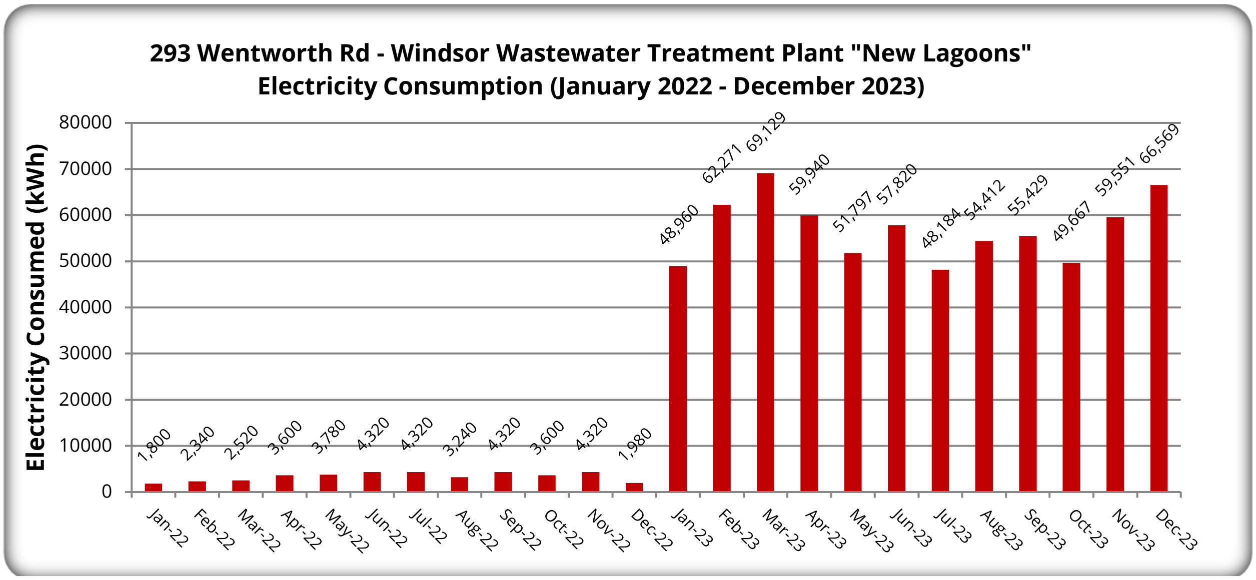

Figure 4.1: 2022/2023 Monthly Electricity Consumption

Figure 4.1 depicts a higher consumption of electricity in 2023, which is expected as that is when the site would have been fully operational. Total electricity usage in the period January 2022/December 2022 was 40,140 kWh and 683,729 kWh in the January 2023/December 2023 year. Due to the site only being operational in 2023, the value for 2022 will not be considered when estimating the electricity production of the PV system.

Facility electricity demand was reviewed for each of the months between January 2022 and December 2023. Figure 4.2 presents a monthly peak demand trend for this 24-month period.

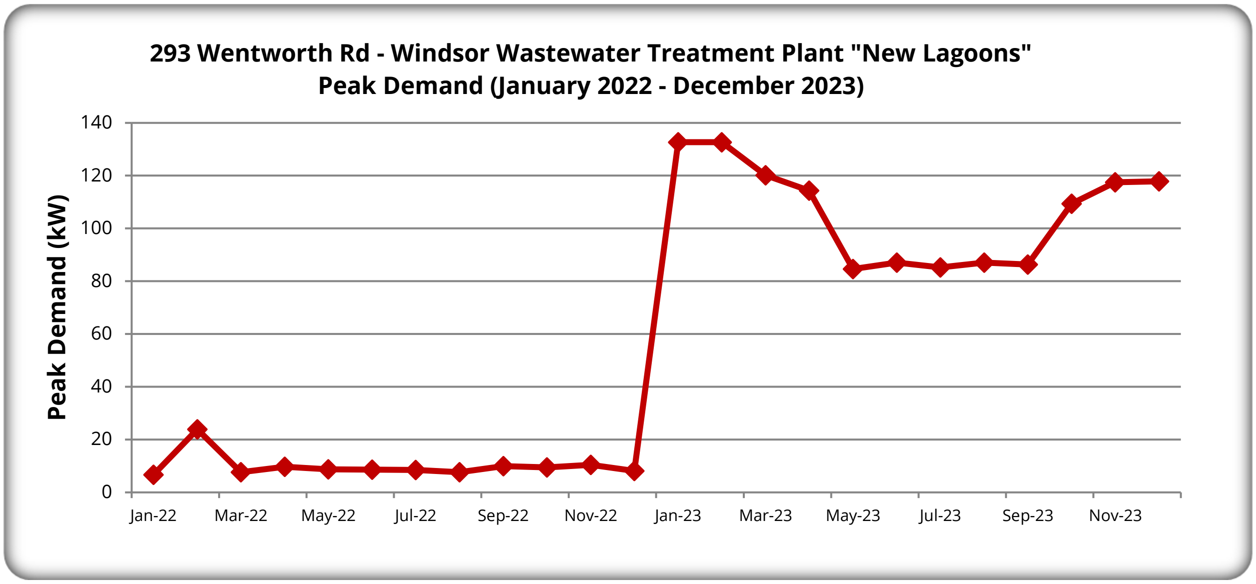

Figure 4.2: Monthly Electricity Peak Demand over 24 Consecutive Months

Figure 4.2 shows a trend that closely follows the kWh consumption. The higher peak demand occurred during the winter months, which coincides with the month with the highest demand for space heating. The monthly peak demand ranges between 6.7 kW and 132.7 kW. The highest demand peak was recorded at 132.7 kW in January and February 2023 while the lowest demand occurred in the month of June 2022 at only 6.7kW.

4.1.2 Electricity Cost

Electricity is provided by the Nova Scotia Power as a "Commercial General Tariff" electricity rate[25].

[25] Source General Tariff| Nova Scotia Power (nspower.ca). Retrieved: 2024-07-22

GENERAL TARIFF

Availability

This tariff is applicable to electric power and energy where the annual consumption is 32,000 kWh or greater and for which no other rates are applicable.

For General tariff customers eligible for the Small General tariff the following conditions apply:

- Customers must make a written request to take service under the Small General tariff.
- Customers can switch rate classes twice in a 24-month period.
- After switching, customers shall take service under this tariff for a minimum of six months subject to meeting the load threshold criteria.

Demand Charge

$10.554 per month per kilowatt of maximum demand

Energy Charge

15.076 ¢ per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of maximum demand
11.779 ¢ per kilowatt hour for all additional kilowatt hours

Figure 4.3: NSPI Commercial General Tariff Rate

The electricity consumption breakdown is depicted in Figure 4.4. This shows that the kWh cost represents about 78.3% and 85.5% of the cost in the monthly power bills in 2022 and 2023, respectively. Monthly electricity cost closely follows the monthly kWh consumption. Total electricity cost in the period January 2022/December 2022 was $5,786 and $91,872 in the January 2023/December 2023 period. Also, the average unit cost of electricity, considering all costs in the bills, was $0.1349/kWh (not including HST) over the 24-month period provided.

An estimated electricity (kWh only) rate for 2024 of $0.1496/kWh was calculated by applying 2024 NSPI Commercial General Tariff rates to 2023 electricity consumption and peak demand values. A 15% HST was also applied. This average kWh rate does not include the additional demand charge, as the implementation of PV to the facility will not reduce the facility's peak demand.

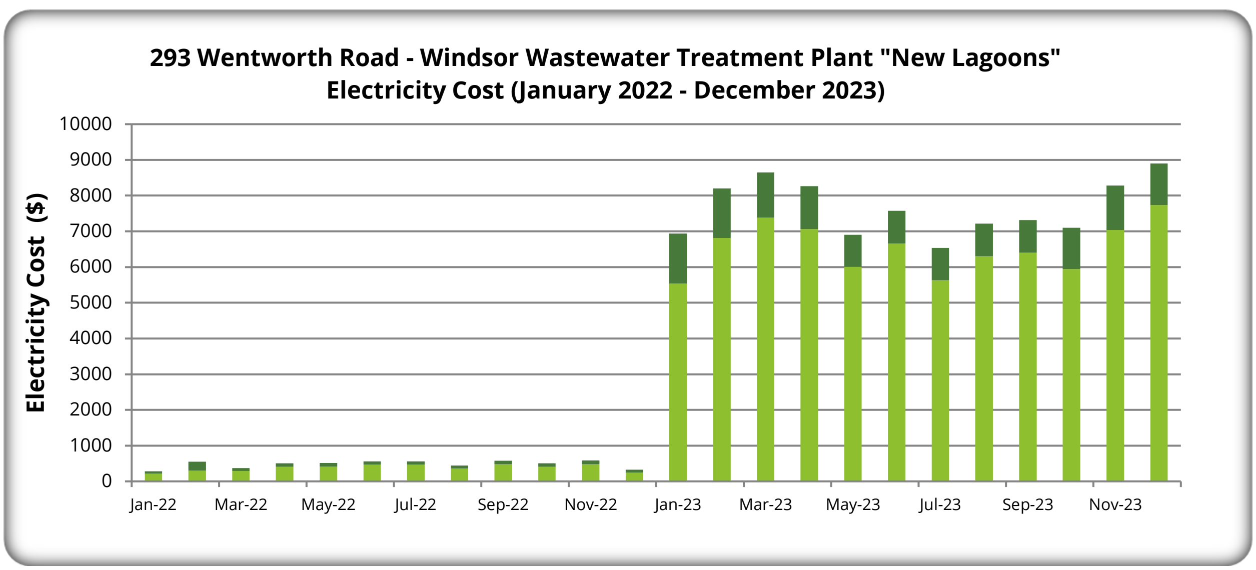

Figure 4.4: Electricity Cost Breakdown

Table 4.1 shows the monthly power bill cost breakdown for the January 2022 to December 2023 24-month period.

Table 4.1: Monthly Power Bill Cost Breakdown for the January 2022 to December 2023

Month-Year	Consumption (kWh)	Consumption Cost ($)	Peak Demand (kW)	Demand Cost ($)	Invoice Amount ($)
January 2022	1,800	$215.52	6.7	$70.33	$285.85
February 2022	2,340	$299.99	23.9	$250.88	$550.87
March 2022	2,520	$290.27	7.6	$79.78	$370.05
April 2022	3,600	$407.09	9.7	$101.82	$508.91
May 2022	3,780	$418.36	8.8	$92.37	$510.73
June 2022	4,320	$468.57	8.6	$90.27	$558.84
July 2022	4,320	$467.91	8.5	$89.22	$557.13
August 2022	3,240	$359.63	7.7	$80.83	$440.46
September 2022	4,320	$477.10	9.9	$103.92	$581.02
October 2022	3,600	$405.78	9.5	$99.72	$505.50
November 2022	4,320	$480.38	10.4	$109.17	$589.55
December 2022	1,980	$242.03	8.1	$85.03	$327.06
January 2023	48,960	$5,541.52	132.7	$1,392.95	$6,934.47
February 2023	62,271	$6,811.52	132.7	$1,392.95	$8,204.47
March 2023	69,129	$7,383.87	120.2	$1,261.74	$8,645.61
April 2023	59,940	$7,059.76	114.3	$1,206.32	$8,266.08
May 2023	51,797	$6,007.25	84.6	$892.87	$6,900.12
June 2023	57,820	$6,657.40	87.1	$919.25	$7,576.65
July 2023	48,184	$5,631.74	85.3	$900.26	$6,532.00
August 2023	54,412	$6,298.85	87.1	$919.25	$7,218.10
September 2023	55,429	$6,401.24	86.4	$911.87	$7,313.11
October 2023	49,667	$5,946.63	109.4	$1,154.61	$7,101.24
November 2023	59,551	$7,039.93	117.5	$1,240.10	$8,280.03
December 2023	66,569	$7,733.82	117.9	$1,168.91	$8,902.73

4.1.3 Total Energy Use Summary

The facility’s total energy usage is shown in Table 4.2. The average for the 24-month period considers the electricity consumption records for January 2022 to December 2023.

Table 4.2: Energy Use Summary

293 Wentworth Road Windsor Wastewater Treatment Plant "New Lagoons"	2022	2023
Electricity		
Annual Electricity and Demand Cost ($)	$5,786	$91,875
Annual Electricity Consumption (kWh)	40,140	683,729
Annual Electricity Consumption (GJ)	144.5	2,461.4
Cost per GJ ($/GJ)	$40.04	$37.33
Percentage of Total Energy (%)	100.0%	100.0%
GHG Emissions (tCO2/yr)	22.4	308.1
kWh Cost w/o demand + HST to be used for Cost Savings Estimations ($/kWh)	$0.1496/kWh	

4.2 NSPI Net Metering Program

The Net Metering Program offered by NSPI provides an incentive for on-site renewable power generation. Using a 2-way meter, NSPI records the amount of power consumed by the facility, as well as any surplus power which is generated on-site using renewable technologies and returned to the grid. NSPI then charges the customer for the difference between energy consumed and energy returned to the grid.

NSPI allows the installation of PV systems of a minimum size of 27kW AC up to a maximum 1000kW AC array for net metering if the NSPI customer has a demand meter which this facility does. If the facility does not have a demand meter, or it is not a winery, farm, or licensed aquaculture plant, the facility could have a PV system with a capacity between 27 and 200 kW AC. If the facility owner has multiple accounts with NSPI, the PV system can supply electricity to other accounts owned by the same person/institution as long as they are within the same geographical area known as NSPI distribution zone.

Annual PV production cannot be higher than the building's annual electricity consumption to qualify for net metering[26].

4.3 Considerations to Size the PV System

The Windsor Wastewater Treatment Plant consumes over 680,000 kWh/yr which makes it a good candidate for a solar PV system with a capacity of about 540 kW (DC). This is the maximum capacity allowed by NSPI for a client that wants to participate in the net metering program. A 540 kW (DC) PV array in Nova Scotia will produce, on average 670,000 kWh (AC) per year, well below the building's annual consumption, thus making the building eligible for the net metering program. The net metering program will permit surplus energy

[26] Source: Commercial Net Metering| Nova Scotia Power (nspower.ca). Retrieved: 2024-07-31

generated from the array to be transferred to the NSPI grid via a bi-directional meter that will record the amount of energy transferred to the grid and credit that amount against future consumption from the grid. This system allows for all energy generated by the array to be used productively without the need or expense of an onsite energy storage system.

4.4 PV System

4.4.1 Ground Mounted

Figure 4.5: Typical Ground Mounted PV Array

The ground mounted PV system can be located on the area west of the building. Water wells and any other infrastructure should be considered when sizing a solar PV array. A typical ground mounted system is shown in Figure 4.5. The implementation of this type of racking system will typically require a geotechnical analysis of the site to be able to design the array foundations. Also, a ballasted PV system can be implemented, which does not require foundations to anchor the racking to the ground. Site conditions are sufficiently typical to permit a standard foundation design for this size of array to be used for this level of analysis. The cost of geotechnical analysis, as part of the detailed system design cost, is included in the capital cost estimate for this array. Also, alternative mounts such as single or dual axis tracking were not considered due to the additional maintenance requirements.

4.5 Technical-Financial and Life Cycle Analyses

The sizing and estimation of energy production from the PV system was completed with the modelling software PVSyst, which is one of the most recognized PV modelling software platforms in the world. The PVSyst model considered the building's load profile or energy consumption, the exact location of the PV array, the site's weather data and solar radiation, estimated near and far shading issues, and estimated panel soiling issues.

This analysis included the installed cost of the PV system and, if applicable, financial incentives, and electrical upgrade cost. Additionally, this analysis considered the degradation in power production over time from the PV modules, string inverter replacement cost after ten (10) to twelve (12) years of operation, inflation rate, annual maintenance cost, and discount rate, among other variables. Usually for string inverters, the replacement cost is about 10% of the PV system installed cost.

Two different PV system arrangements were assessed to determine which system shows the better financial performance, such as the lowest levelized cost of electricity and simple payback. The system was evaluated considering standard panels (monofacial) and bi-facial panels. These options include:

1. **Option A:** 330 kWp DC, 300 kW AC PV system with monofacial panels. Net metering.
2. **Option B:** 327 kWp DC, 300kW AC PV system with bifacial panels. Net metering.

4.5.1 Financial Assumptions

The following list includes all the assumptions and variables considered for the technical and financial analysis of both roof and ground mounted PV systems.

- Solar PV modules capacity: monofacial 555 W; bifacial 550 W
- Inverter: String inverter
- PV panel orientation and angle: due south at a 40° angle for ground mounted
- Building annual electricity consumption
- PV system modelled with software PVSyst
- General Inflation rate: 3%
- NSPI Electricity Inflation Rate: 4%
- O&M Inflation Rate: 4%
- Discount rate: 6.5%
- Interest rate: 6.5%
- Life of the project: 25 years
- Equity Ratio: 100% equity if capital <$150,000. If capital is >$150,000, consider $150,000 as equity and the rest as a loan, 20 year loan term if capital >$150,000.
- NS Power GHG emission intensity factor: 0.4506 CO_2e kg/kWh in 2023[27]
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: %0.5 of CAPEX/yr
- String inverter replacement cost in year 12 (10% of CAPEX)

4.5.2 PV Systems Cost

Solar PV contractors in Nova Scotia were contacted to obtain budgetary installed costs for the proposed PV system arrangements, including Supernova Solar, Wattup Solar, and Natural Forces. It was determined that the average installed price for PV arrays with monofacial or standard panels is $2,175-3,000/kWp DC and with bifacial modules is $2,200-$3,075/kWp DC, depending on the system size, racking system, inverter technology (string versus microinverter), and PV installer. These budgetary installed costs do not include HST.

[27] Source: https://www.nspower.ca/cleanandgreen/air-emissions-reporting. Retrieved: 2024-08-09

This pricing excludes the costs for a geotechnical analysis and any required electrical upgrades and structural modifications to accommodate the new PV system.

4.5.3 Geotechnical Analysis and Cost

Foundation designs of solar photovoltaic (PV) arrays commonly consist of ballasted footings founded at the ground surface (i.e., precast concrete pads), or anchored footings consisting of shallow, driven pile, or helical screw pile foundations embedded below ground. PV arrays also include supporting infrastructure such as service roads, storage shipping containers, electrical substations with transformers, concrete pads for electrical equipment, battery storage systems, etc. that each have their own unique foundation requirements.

Geotechnical investigations in support of PV arrays commonly consist of either test pit or borehole drilling investigations. The decision to excavate test pits versus drill boreholes is determined based on site specific requirements and considerations. A desktop study and site visit can help better define the geotechnical field investigation requirements. Underground utility locating should be completed prior to conducting the field investigations.

Geotechnical reports will often be structured in the following way:

- Introduction
- Project and Site Description
- Fieldwork Procedure
- Summarized Subsurface Conditions
- Discussions and Recommendations [including earthworks, foundation design for PVs and associated infrastructure (i.e., bearing capacity and settlement), slope stability, trenching, service roads, construction monitoring, etc.]

In-situ and laboratory testing on soils is conducted to characterize various index, strength, and environmental properties of the soils. This testing may include:

- Standard penetration testing (SPT)
- Moisture content
- Grain size analysis
- Proctor density
- Unconfined compressive strength (UCS) of rock
- Basic chemical testing relating to corrosion of buried concrete and steel including pH, sulphate, and chloride
- Thermal conductivity
- In-situ electrical resistivity
- Other in-situ strength tests as required
- Other environmental quality tests as required

4.5.3.1 Site Description

The site is located at the Windsor Wastewater Treatment Plant at 293 Wentworth Road, Windsor, NS. The site contains several wastewater treatment ponds and a control building as shown in Figure 4.6 and Figure 4.7. The ponds are encircled by berms built up above the existing grade. The height and geometry of the berms is unknown at this time, but it is assumed that the berms are at least 2-3 m tall, with a minimum of 2 horizontal to 1 vertical (2H:1V) side slopes. The fill material used to construct the berms and level the site is unknown at this time. Anchored PV foundations are proposed along the east and west ends of the site as shown in Figure 4.6. Ballasted PV foundations are proposed in the centre of the site where the PVs will be situated on the berm slope.

Based on geologic mapping, the principal soil unit in the area is ground moraine and streamlined drift till. The till is described as silty, compact, material derived from both local and distant sources[28].

Figure 4.6: Ortho – 293 Wentworth Road - Ballasted PV array area (yellow), anchored PV array (blue) (GoogleEarth, 2024)

[28] Stea, R.R., Conley, H., Brown, Y. (1992). Surficial Geology of the Province of Nova Scotia – Map 92-3.

Figure 4.7: LiDAR – 293 Wentworth Road

4.5.3.2 Potential Geotechnical Challenges

Potential geotechnical challenges include:

- Unknown fill materials at the site.
- Unknown placement and compaction method for fill materials at the site.
- Proximity to potential soft marine sediments.
- Mobilizing drill rig or excavator near berm slopes.
- Slope stability.
- Bearing capacity.
- Differential settlement fill materials (if ballasted foundations are selected).
- Frost heave of fill materials (if ballasted foundations are selected).
- Damage to the liner of a lagoon during investigation and construction (liner is likely keyed into the crest of the berms).
- Damage to the crest and slope of lagoon during construction.
- Unknown location of lagoon piping, etc.
- Restricted access to crest of berm.
- Restricted view and access of downstream side of lagoon berms that may impede routine maintenance and surveillance.
- Misalignment of ballasted PVs due to settlement or frost heave (if ballasted foundations are selected).
- Misalignment of ballasted PVs due to settlement or frost heave.
- PV system wiring may need to run through the above-ground conduits and not in underground trenches to preserve berm stability.

4.5.3.3 Suggested Geotechnical Study

To support the PV array foundation design, the following geotechnical study is suggested:

- Geotechnical borehole investigation.
- Approximately 6-8 boreholes (at least 2 at each proposed PV location).

- Approximately 3 monitoring wells to assist with groundwater level determination.
- Boreholes drilled to approximately 6-8 m.
- In-situ and laboratory testing and geotechnical report as described above in General Geotechnical Requirements.

4.5.3.4 Cost Estimate

The cost of the proposed geotechnical investigation would be in the range of $25k - $35k.

4.5.4 Electrical Analysis and Cost

For this site, interconnection with the main MCC is likely the most effective means of connecting the PV system. This location is primarily powered by a three-phase 600V distribution system.

In this option, the PV system size is restricted to the present energy consumption of the site. Therefore, no upgrade to the service entrance is required. A means of interconnecting the inverters with the existing distribution system will be required.

A system at 300kW would export 288A. This is too large to add to the MCC, as it would become overloaded. We recommend installing a splitter and a 400A fused disconnect switch between the load terminal and the MCC. The other lugs on that splitter would be used to interconnect the PV system.

Per NSPI Bulletin B-64-200, a control system will be required to ensure the PV system shuts down upon loss of the utility interconnection.

Table 4.3: Estimated Electrical Work Cost

Item	Estimated Cost	Notes
Interconnection Wiring	$3000	
600A Splitter, NEMA 1	$2000	
1 x 300kVA Transformer, NEMA 3R	$30,000	Not required if the inverters could be connected at 600A
1 x 400A Disconnect Switch, complete with 400A Fuses	$3,000	
2 x 150A Disconnect Switch, complete with 150A Fuses	$5,000	
Total	**$43,000**	-

4.5.5 PV System – Net Metering

This PV system was sized considering that all the energy produced has to be consumed onsite and no surplus energy can be exported to the grid. This system would be equipped with a power production control system to monitor the building load to adapt the PV system production and to make sure there is no surplus energy sent back to the grid.

Figure 4.8 shows the 3D models in PVSyst and the area considered for the implementation of the PV system considering monofacial (Option A) and bifacial panels (Option B). The following items were considered when placing the PV system on this part of the property:

- No shading issues due to the proximity to nearby taller structures.
- Relatively flat surface.
- Proximity to the main building, which facilitates their interconnection.
- Excellent exposure to due south.
- Excellent visibility for the facility operators and the public.
- Easy access for maintenance.
- Racking system for PV systems nearest to the lagoons will be ballasted. The PV array furthest from the lagoon will be anchored to the ground.

Figure 4.8: Ground Mounted PV Array – Option A and B

The estimated energy generation from the PVSyst model, as well as the estimated installed cost, current electricity rate, building annual energy consumption, and PV system specific production is included in Table 4.4. The PVSyst reports are included in Appendix B. Costs in the table below include HST.

Table 4.4: Ground Mounted PV System – Options A and B

293 Wentworth Road Windsor WWTP – Net Metering	Option A - 330 kWp DC Monofacial	Option B – 327 kWp DC Bifacial
Ground Mount PV Capacity (kWp DC)	330	327
Ground Mount PV Capacity (kWp AC)	300	300
Ground Mount Installed Cost ($/kWp)	$2,943	$2,986
Ground Mount Cost [PV only] ($)	$971,190	$976,422
Electricity Rate ($/kWh)	$0.1496	$0.1496
Annual Consumption (kWh/yr)	683,729	683,729

293 Wentworth Road Windsor WWTP – Net Metering	Option A - 330 kWp DC Monofacial	Option B – 327 kWp DC Bifacial
Generated by PV and Consumed on Site (kWh/yr)	228,379	236,171
Generated by PV and Exported to Grid (kWh/yr)	194,496	216,014
PV Generation (kWh/yr)	422,874	452,185
PV Specific Production (kWh/yr/kWp)	1,281	1,383

When comparing the results considering monofacial panels (Option A) and bifacial panels (Option B), the following was observed:

- The installed cost per kWp for bifacial panels is approximately 1.5% higher than for monofacial panels.
- All electricity generated by the PV system would be consumed onsite.
- Surplus energy is not generated with the considered building energy consumption.
- Option A would provide 61.8% of the annual energy consumption.
- Option B would provide 66.1% of the annual energy consumption.
- All energy produced onsite will generate a cost savings at the same rate (NSPI electricity rate).
- The production and specific production from Option B (bifacial) is 6.9% and 7.9% higher respectively when compared to Option A, even though Option B kWp DC installed capacity is only 0.91% smaller than Option A.

In addition to these PV costs, other costs should be considered in the financial analysis. Table 4.5 shows the PV installation cost, as well as the electrical upgrade cost, geotechnical analysis, and design cost. As expected, the highest installation cost is for Option B, which also results in the highest total cost.

Table 4.5: PV Cost and Additional Costs - Options A and B

Installed Cost	Option A – 330 kWp DC Monofacial	Option B - 327 kWp DC Bifacial
PV Ground Mounted ($)	$971,190	$976,422
Geotechnical Analysis Cost ($)	$35,000	$35,000
Electrical Upgrade Cost ($)	$43,000	$43,000
Design ($)	$50,500	$50,500
Total Project Cost ($)	**$1,099,690**	**$1,104,922**

Considering all these costs and the total savings, the following tables show the simple payback, net present value for a 25-year project horizon, life cycle costs (LCC), and the CO_2 emission reductions. Total savings include the energy savings and annual maintenance cost. Maintenance cost includes cleaning the panels twice a year, tightening the mechanical and electrical connections once a year, spot measurements once a year, and remote review of the system performance every three or four months.

Table 4.6: Financial Analysis – Options A and B

Windsor Wastewater Treatment Plant	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option A - 330 kWp DC Monofacial	$1,099,690	$58,407	$63,263	18.8	-$15,738	3.2	102.9
Option B - 327 kWp DC Bifacial	$1,104,922	$62,765	$67,648	17.6	$56,350	4.6	106.4

Option A has a lower installation cost but Option B has higher savings, which results in a shorter simple payback period. The cash flow and LCOE for both projects should be reviewed to further assess these options. The cash flow includes the maintenance cost and the savings from the generated electricity. Typically, a PV system fitted with string inverters requires the replacement of the inverters after ten (10) to twelve (12) years of operation, which results in a high maintenance cost in year 11 or 12.

4.5.5.1 Levelized Cost of Energy (LCOE)

The LCOE measures lifetime costs divided by energy production. It calculates the present value of the total cost of implementing and operating the building over an assumed lifetime. LCOE allows the comparison of different PV projects and different technologies (e.g., wind, solar, natural gas) of unequal life spans, project size, different capital cost, risk, return, and capacities. Figure 4.9 shows the LCOE formula.[29]

The LCOE calculation for this project considered the following variables:

- O&M Inflation rate: 4%
- Discount rate: 6.5%
- Life of the project: 25 years
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr (the same as in the previous section).
- Inverter replacement cost in year 12 (10% of CAPEX).

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

I_t = Investment expenditures in year t (including financing)
M_t = Operations and maintenance expenditures in year t
F_t = Fuel expenditures in year t
E_t = Electricity generation in year t
r = Discount rate
n = Life of the system

Figure 4.9: LCOE Formula

[29] Source: https://www.energy.gov/sites/prod/files/2015/08/f2/LCOE.pdf. Retrieved: 2020-02-05

Table 4.7 shows the costs included in the calculation of the LCOE and the estimated annual energy production factoring power production depreciation. The LCOE for Option A was determined to be $0.4042/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE of the purchase of electricity from the grid is $0.2176/kWh, which is lower than the LCOE for the PV system.

Table 4.7: LCOE Calculation – Option A

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000	-	-	-
1	-	$85,191	-$4,856	422,874
2	-	$85,191	-$5,050	418,645
3	-	$85,191	-$5,252	416,552
4	-	$85,191	-$5,462	414,469
5	-	$85,191	-$5,681	412,397
6	-	$85,191	-$5,908	410,335
7	-	$85,191	-$6,144	408,283
8	-	$85,191	-$6,390	406,242
9	-	$85,191	-$6,646	404,211
10	-	$85,191	-$6,912	402,190
11	-	$85,191	-$7,188	400,179
12	-	$85,191	-$104,595	398,178
13	-	$85,191	-$7,775	396,187
14	-	$85,191	-$8,086	394,206
15	-	$85,191	-$8,409	392,235
16	-	$85,191	-$8,745	390,274
17	-	$85,191	-$9,095	388,322
18	-	$85,191	-$9,459	386,381
19	-	$85,191	-$9,837	384,449
20	-	$85,191	-$10,231	382,527
21	-	-	-$10,640	380,614
22	-	-	-$11,066	378,711
23	-	-	-$11,508	376,817
24	-	-	-$11,969	374,933
25	-	-	-$12,447	373,059

The LCOE for Option B was determined to be $0.3799/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE of the purchase of electricity from the grid is $0.2176/kWh, which is lower than the LCOE for the PV system.

The LCOE for the NSPI grid was calculated considering inflation rate and the annual energy consumption of the building.

Table 4.8: LCOE Calculation – Option B

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000	-	-	-
1	-	$85,660	-$4,882	452,185
2	-	$85,660	-$5,077	447,663
3	-	$85,660	-$5,280	445,425
4	-	$85,660	-$5,492	443,198
5	-	$85,660	-$5,711	440,982
6	-	$85,660	-$5,940	438,777
7	-	$85,660	-$6,177	436,583
8	-	$85,660	-$6,425	434,400
9	-	$85,660	-$6,682	432,228
10	-	$85,660	-$6,949	430,067
11	-	$85,660	-$7,227	427,917
12	-	$85,660	-$105,158	425,777
13	-	$85,660	-$7,816	423,648
14	-	$85,660	-$8,129	421,530
15	-	$85,660	-$8,454	419,422
16	-	$85,660	-$8,792	417,325
17	-	$85,660	-$9,144	415,238
18	-	$85,660	-$9,510	413,162
19	-	$85,660	-$9,890	411,096
20	-	$85,660	-$10,286	409,041
21	-	-	-$10,697	406,996
22	-	-	-$11,125	404,961
23	-	-	-$11,570	402,936
24	-	-	-$12,033	400,921
25	-	-	-$12,514	398,917

Table 4.9 summarizes the results of the financial assessment for both options. Option B shows the highest NPV and lower LCOE compared to Option A.

Table 4.9: Summary - Financial Analysis - Options A and B

Windsor Wastewater Treatment Plant	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	LCOE $/kWh	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option A 330 kWp DC Monofacial	$1,099,690	$58,407	$0.4042	18.8	-$15,738	3.2	102.9
Option B - 327 kWp DC Bifacial	$1,104,922	$62,765	$0.3799	17.6	$56,350	4.6	106.4

Considering that Option B was shown to have the highest NPV and lower LCOE compared to Option A, a sensitivity analysis around the total implementation cost was performed. Table 4.10 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

4.5.5.2 Sensitivity Analysis – CAPEX

A sensitivity analysis around the total implementation cost was performed. Table 4.10 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

Table 4.10: CAPEX Sensitivity Analysis

PV System	CAPEX Variance +/-%	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	LCOE ($/kWh)	Utility LCOE ($/kWh)
Option B - 327kWp Bifacial DC Bifacial	0%	$1,104,922	$62,765	$67,648	17.6	$56,350	4.6	$0.3799	$0.2176
	30%	$1,436,399			22.9	-$311,032	-1.3	$0.5007	$0.2176
	-20%	$883,938			14.1	$301,271	10.0	$0.2994	$0.2176

4.5.5.3 Sensitivity Analysis – Energy Generation

A sensitivity analysis around the total energy generation was performed. Table 4.11 shows what the simple payback and LCOE range would be if the electricity generation varied between -5% and +5%.

Table 4.11: Sensitivity Around kW/yr Generation

PV System	+/- % kWh/yr	kWh/yr	Total Savings ($/yr)	Simple Payback (yr)	LCOE $/kWh	Utility LCOE ($/kWh)
Option B - 327 kWp DC	-	452,185	$62,765	17.6	$0.3799	$0.2176
	-5%	429,576	$59,383	18.6	$0.3999	$0.2176
	5%	474,794	$66,148	16.7	$0.3618	$0.2176

4.6 PV Project Estimated Timeline

The implementation of any of these projects will require the completion of a number of tasks. Considering that an engineering company produces the design and tender package, and a solar PV contractor installs the system (turn-key project), a project timeline was estimated. The tables below depict the estimated timeline to complete the options described for this site.

Table 4.12: Estimated Timeline for Option A and B

Task #	Option A and B - Tasks - 330 kWp Monofacial and 327 kWp Bifacial PV Systems	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
1	RFP process to design and create the tender package for the PV system. Select PV designer. If WHRM requires an Engineer to act as Owner's Engineer, an RFP to select it could occur in parallel to the RFP to select the PV designer.	6	6	weeks after RFP was issued
2	PV Designer: Kick-off Meeting, Available Information Review	1	7	weeks after RFP was issued
3	PV Designer: Site Visit	1	8	weeks after RFP was issued
4	PV Designer: PV System Design and Tender Package Preparation	8	16	weeks after RFP was issued
5	WHRM: Design and Tender Package Review	1	17	weeks after RFP was issued
6	PV Designer: Design and Tender Package Update According to WHRM Comments	1	18	weeks after RFP was issued
7	WHRM: Tender Package Is Issued	1	19	weeks after RFP was issued
8	Bidders: Tender Period, Question and Answer Period. Bids are submitted to WHRM.	4	23	weeks after RFP was issued
9	WHRM or Owner's engineer: Bid Assessment, Question and Answer with bidders, Bids	3	26	weeks after RFP was issued

Task #	Option A and B - Tasks - 330 kWp Monofacial and 327 kWp Bifacial PV Systems	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
	Ranking and Recommendation. Successful bidder is contacted.			
10	WHRM: Negotiation with Successful Bidder. Contract signing.	2	28	weeks after RFP was issued
11	PV Contractor: Kick-off Meeting, Available Information Review, Site Visit.	2	30	weeks after RFP was issued
12	PV Contractor: Equipment Selection and Acquisition. PV System Installation.	14	44	weeks after RFP was issued
13	WHRM or Owner's Engineer: Design drawings and Shop Drawings Review. Site visits. Communications with PV Contractor (in parallel to above).	14	44	weeks after RFP was issued
14	PV Contractor: System Start-up	1	45	weeks after RFP was issued
15	WHRM or Owner's Engineer: As-built Document and Drawings Review. System Commissioning. Commissioning Report.	4	49	weeks after RFP was issued

5 48 Falmouth Connector - Falmouth Wastewater Treatment Plant

5.1 Review of Historic Energy Performance

The Falmouth Wastewater Treatment Plant located at 48 Falmouth Connector in Falmouth, NS, provided electricity bills for a 24-month period spanning January 2022 to December 2023. Energy consumption and demand were reviewed in annual terms to ensure that variation in seasonality was observable. With at least two periods available, a month-to-month comparison of the facility's energy performance was made from one year to the next. Review of electricity consumption profiles based on the information obtained from the two periods was discussed and is compared in this section. This review will also include observed variations in electricity demand by month across the two annual periods.

5.1.1 Electricity Use Profiles

Figure 5.1 provides the monthly electricity usage profile which shows the 24-month period from January 2022 to December 2023.

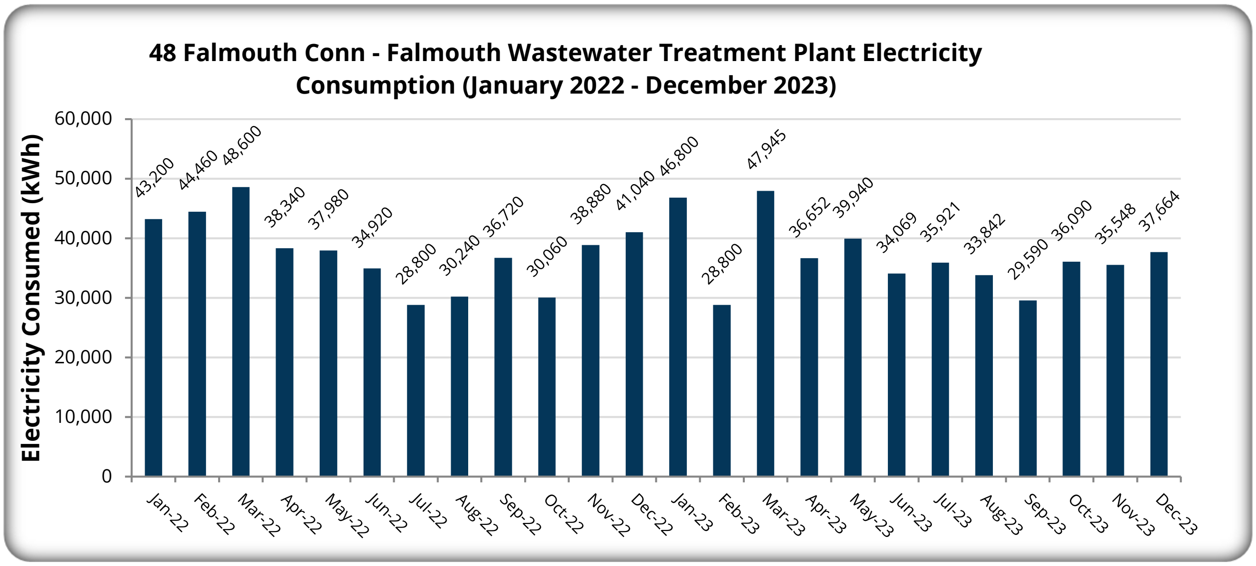

Figure 5.1: 2022/2023 Monthly Electricity Consumption

Figure 5.1 depicts a trend that shows a higher electricity consumption in the winter months, which is most likely due to the demand for heating within the building. Total electricity usage in the period January 2022/December 2022 was 453,240 kWh and 442,861 kWh in the January 2023/December 2023 year. The average annual energy consumption considering these two 12-month periods is 448,051 kWh.

Facility electricity demand was reviewed for each of the months between January 2022 and December 2023. Figure 5.2 presents a monthly peak demand trend for this 24-month period.

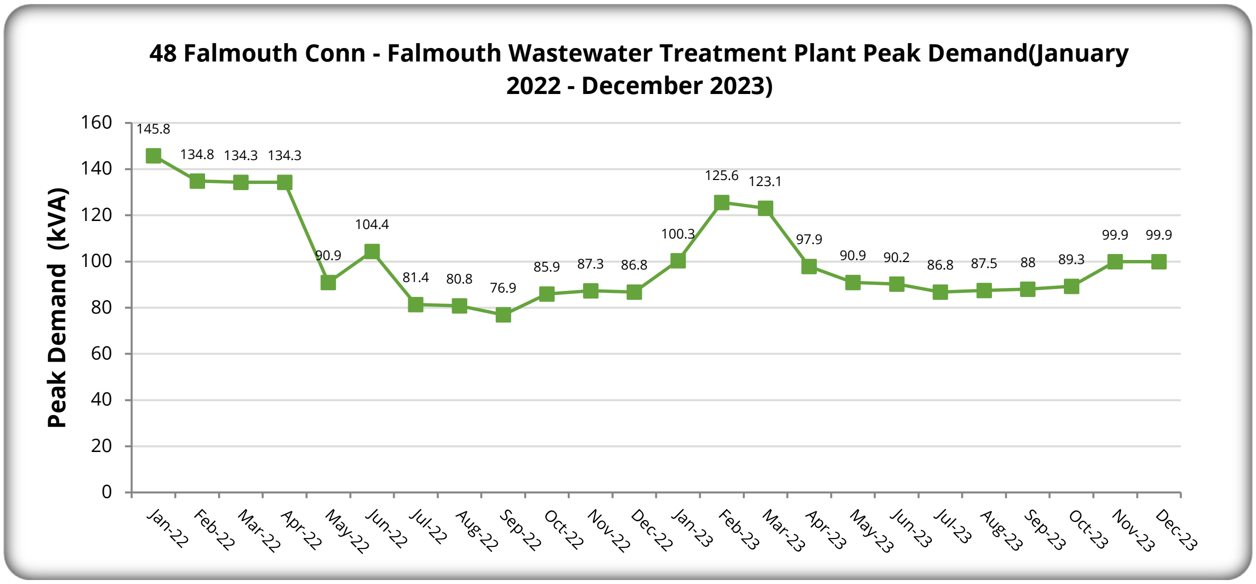

Figure 5.2: Monthly Electricity Peak Demand over 24 Consecutive Months

Figure 5.2 shows a trend that closely follows the kWh consumption. The higher peak demand occurred during the winter months, which coincides with the month with the highest demand for space heating. The monthly peak demand ranges between 76.9 kVA and 145.8 kVA. The highest demand peak was recorded at 145.8 kVA in January 2022 while the lowest demand occurred in the month of September 2022 at only 76.9kVA.

5.1.2 Electricity Cost

Electricity is provided by the Nova Scotia Power as a "Small Industrial Tariff" electricity rate[30].

[30] Source General Tariff| Nova Scotia Power (nspower.ca). Retrieved: 2024-07-22

SMALL INDUSTRIAL TARIFF

Availability

This tariff is applicable to electric power and energy supplied to any customer, for industrial use, including farming and processing, where the regular billing demand is less than 250 kV.A or 225 kW.

Demand Charge

$8.332 per month per kilovolt ampere of maximum demand

Energy Charge

14.05¢ per kilowatt hour for the first 200 kilowatt hours per month per kilovolt ampere of maximum demand
11.476¢ per kilowatt hour for all additional kilowatt hours

Figure 5.3: NSPI Small Industrial Tariff Rate

The electricity consumption breakdown is depicted in Figure 5.4. This shows that the kWh cost represents about 83.4% and 83.7% of the cost in the monthly power bills in 2022 and 2023, respectively. Monthly electricity cost closely follows the monthly kWh consumption. Total electricity cost in the period January 2022/December 2022 was $57,664 and $59,239 in the January 2023/December 2023 period. The average annual electricity cost considering this two 12-month period is $58,452. Also, the average unit cost of electricity, considering all costs in the bills, was $0.1305/kWh (not including HST) over the 24-month period provided.

An estimated electricity (kWh only) rate for 2024 of $0.1479/kWh was calculated by applying 2024 NSPI Commercial General Tariff rates to 2023 electricity consumption and peak demand values. A 15% HST was also applied. This average kWh rate does not include the additional demand charge, as the implementation of PV to the facility will not reduce the facility's peak demand.

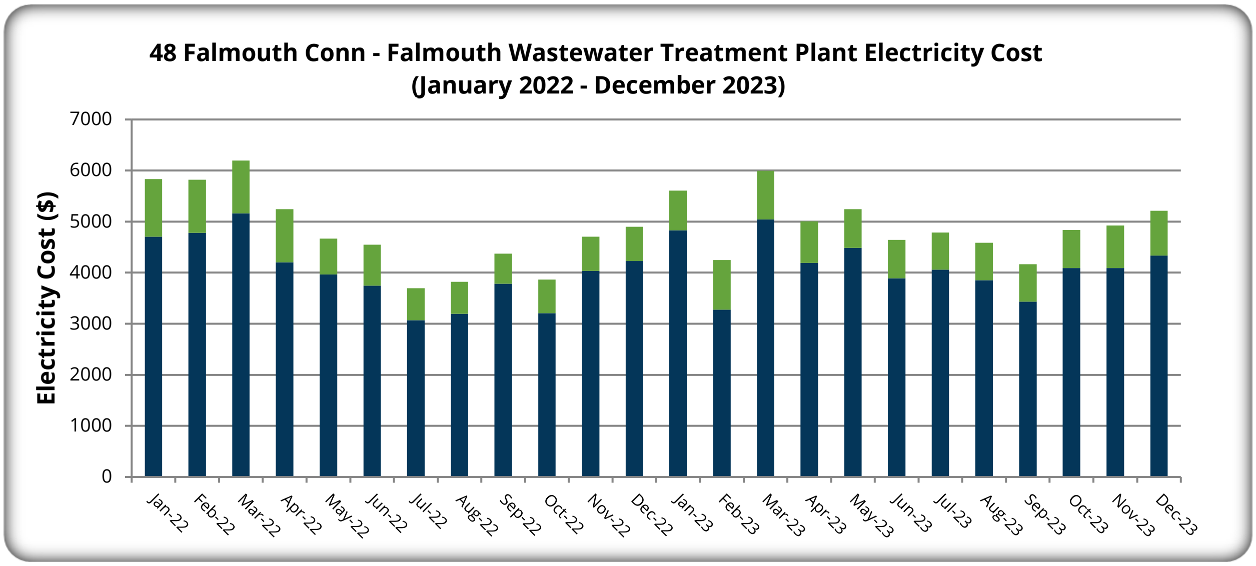

Figure 5.4: Electricity Cost Breakdown

Table 5.1 shows the monthly power bill cost breakdown for the January 2022 to December 2023 24-month period.

Table 5.1: Monthly Power Bill Cost Breakdown for the January 2022 to December 2023

Month-Year	Consumption (kWh)	Consumption Cost ($)	Peak Demand (kVA)	Demand Cost ($)	Invoice Amount ($)
January 2022	43,200	$4,704.87	145.8	$1,124.70	$5,829.57
February 2022	44,460	$4,777.24	134.8	$1,039.85	$5,817.09
March 2022	48,600	$5,159.87	134.3	$1,035.99	$6,195.86
April 2022	38,340	$4,205.69	134.3	$1,035.99	$5,241.68
May 2022	37,980	$3,965.31	90.9	$701.20	$4,666.51
June 2022	34,920	$3,745.13	104.4	$805.34	$4,550.47
July 2022	28,800	$3,066.35	81.4	$627.92	$3,694.27
August 2022	30,240	$3,197.41	80.8	$623.29	$3,820.70
September 2022	36,720	$3,781.47	76.9	$593.21	$4,374.68
October 2022	30,060	$3,204.98	85.9	$662.63	$3,867.61
November 2022	38,880	$4,031.91	87.3	$673.43	$4,705.34
December 2022	41,040	$4,230.41	86.8	$669.58	$4,899.99
January 2023	46,800	$4,830.43	100.3	$773.71	$5,604.14
February 2023	28,800	$3,277.01	125.6	$968.88	$4,245.89
March 2023	47,945	$5,045.58	123.1	$949.59	$5,995.17
April 2023	36,652	$4,191.54	97.9	$815.70	$5,007.24
May 2023	39,940	$4,486.31	90.9	$757.38	$5,243.69
June 2023	34,069	$3,892.03	90.2	$751.55	$4,643.58
July 2023	35,921	$4,060.86	86.8	$723.22	$4,784.08
August 2023	33,842	$3,855.30	87.5	$729.05	$4,584.35
September 2023	29,590	$3,430.07	88	$733.22	$4,163.29
October 2023	36,090	$4,090.73	89.3	$744.05	$4,834.78
November 2023	35,548	$4,090.77	99.9	$832.37	$4,923.14
December 2023	37,664	$4,331.87	99.9	$878.02	$5,209.89

5.1.3 Total Energy Use Summary

The facility's total energy usage is shown in Table 5.2. The average for the 24-month period considers the electricity consumption records for January 2022 to December 2023.

Table 5.2: Energy Use Summary

Falmouth Wastewater Treatment Plant	2022	2023
Electricity		
Annual Electricity and Demand Cost ($)	$57,664	$59,239
Annual Electricity Consumption (kWh)	453,240	442,861
Annual Electricity Consumption (GJ)	1,631.7	1,594.3
Cost per GJ ($/GJ)	$35.34	$37.16
Percentage of Total Energy (%)	100.0%	100.0%
GHG Emissions (tCO_2/yr)	252.5	199.6
kWh Cost w/o demand + HST to be used for Cost Savings Estimations ($/kWh)	$0.1479/kWh	

5.2 NSPI Net Metering Program

The Net Metering Program offered by NSPI provides an incentive for on-site renewable power generation. Using a 2-way meter, NSPI records the amount of power consumed by the facility, as well as any surplus power which is generated on-site using renewable technologies and returned to the grid. NSPI then charges the customer for the difference between energy consumed and energy returned to the grid.

NSPI allows the installation of PV systems of a minimum size of 27kW AC up to a maximum 1000kW AC array for net metering if the NSPI customer has a demand meter which this facility does. If the facility does not have a demand meter, or it is not a winery, farm, or licensed aquaculture plant, the facility could have a PV system with a capacity between 27 and 200 kW AC. If the facility owner has multiple accounts with NSPI, the PV system can supply electricity to other accounts owned by the same person/institution as long as they are within the same geographical area known as NSPI distribution zone.

Annual PV production cannot be higher than the building's annual electricity consumption to qualify for net metering[31].

5.3 Considerations to Size the PV System

The Falmouth Wastewater Treatment Plant consumes over 440,000 kWh/yr which makes it a good candidate for a solar PV system with a capacity of about 350 kW (DC). This is the maximum capacity allowed by NSPI for a client that wants to participate in the net metering program. A 350 kW (DC) PV array in Nova Scotia will produce, on average 440,000 kWh (AC) per year, below the building's annual consumption, thus making the building eligible for the net metering program. The net metering program will permit surplus energy generated from the array to be transferred to the NSPI grid via a bi-directional meter that will record

[31] Source: Commercial Net Metering| Nova Scotia Power (nspower.ca). Retrieved: 2024-07-31

the amount of energy transferred to the grid and credit that amount against future consumption from the grid. This system allows for all energy generated by the array to be used productively without the need or expense of an onsite energy storage system. Alternatively, a PV system larger than 100 kW AC could be installed as long as all the energy produced is consumed onsite and energy is not exported to the grid.

5.4 PV System

5.4.1 Ground Mounted

The ground mounted PV system can be located on the area west of the building. Water wells and any other infrastructure should be considered when sizing a solar PV array. A typical ground mounted system is shown in Figure 5.5. The implementation of this type of racking system will typically require a geotechnical analysis of the site to be able to design the array foundations. Also, a ballasted PV system can be implemented, which does not require foundations to anchor the racking to the ground. Site conditions are sufficiently typical to permit a standard foundation design for this size of array to be used for this level of analysis. The cost of geotechnical analysis, as part of the detailed system design cost, is included in the capital cost estimate for this array. Also, alternative mounts such as single or dual axis tracking were not considered due to the additional maintenance requirements.

Figure 5.5: Typical Ground Mounted PV Array

5.4.2 Roof Mounted

A PV system can be accommodated on the flat roof with a ballasted racking system. Panels could be placed in landscape position, oriented towards the south at an angle of 10°. Alternatively, a PV system can also be accommodated on a pitched roof, with the panels oriented on a southern roof face at an angle matching the roof slope. This measure should only be considered when the building roof is

Figure 5.6: Typical Ballasted Roof Mounted PV Array

due for replacement or if it can be determined that the existing roofing system has at least 25 years of remaining life.

HVAC equipment and any other infrastructure should be considered when sizing a solar PV array. A typical roof mounted system is shown in Figure 5.6.

The implementation of a system of this type will require a structural assessment of the roof to determine if it can withstand the load from the PV panels. If the assessment determines that the roof structure cannot withstand the load, then the roof structure will need to be reinforced. The estimated implementation cost includes the cost for the structural assessment, but it does not include the cost for the roof reinforcement (this cost is determined or estimated after the completion of the structural assessment).

5.5 Incentive Programs

5.5.1 Low Carbon Communities Program

West Hants Regional Municipality may be eligible for the *Low Carbon Communities Program.* The program offers funding to recover up to 75% of the total project costs to a maximum of $75,000.The program provides 90% of the funding at the start of the project and the remaining 10% when the project is completed and the final reports submitted. No more than 75% of the total project cost can be funded through the provincial government[32]. This program requires that reduction in GHG emissions be demonstrated. The expected reductions in capital cost for this project, due to this incentive program, are included in the financial analysis. Further details about the requirements from this program can be found here: Low Carbon Communities - Government of Nova Scotia, Canada. The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

5.5.2 Green Municipal Fund: Local Energy Generation

West Hants Regional Municipality may be eligible for the Green Municipal Fund's *Community Energy Systems: Capital Projects* grant and loan program. The program offers a combined grant and loan up to 80% of eligible project costs to a maximum of $10,000,000. With the grant being eligible for up to 15% of project costs. This program requires the completion of a feasibility study which considers technical and financial, as well as the social and environmental impacts of the project[33]. Further details about the requirements from this program can be found here: Capital project: Community Energy Systems (greenmunicipalfund.ca).

[32] Source: Low Carbon Communities - Government of Nova Scotia, Canada. Retrieved: 2024-07-31
[33] Source: Capital project: Community Energy Systems (greenmunicipalfund.ca). Retrieved: 2024-07-31

5.5.3 Sustainable Communities Challenge Fund

West Hants Regional Municipality may be eligible for the *Sustainable Communities Challenge Fund: Mitigation Stream*. This fund provides grants up to 80% of eligible projects costs to a maximum of $1,000,000. The applicant must supply a minimum of 20% of eligible project costs, which may be made by alternate funding sources such as federal funding sources. This program requires that reduction in GHG emissions be demonstrated[34]. Further details about the requirements from this program can be found here: Funding Opportunities - Sustainable Communities Challenge Fund (nschallengefund.ca). The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

5.5.4 Low Carbon Economy Challenge

West Hants Regional Municipality may be eligible for the *Low Carbon Economy*. This fund provides grants up to 50% of eligible projects costs for provincial municipalities. The fund ranges from a minimum of $1,000,000 to a maximum of $25,000,000 in available funding. According to the program, the project must produce electricity for the facility's own use. Eligible projects must result in a reduction in GHG emissions. Further details about the requirements from this program can be found here: Low Carbon Economy Challenge Applicant Guide 2023 - Canada.ca.[35] The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

5.6 Technical-Financial and Life Cycle Analyses

The sizing and estimation of energy production from the PV system was completed with the modelling software PVSyst, which is one of the most recognized PV modelling software platforms in the world. The PVSyst model considered the building's load profile or energy consumption, the exact location of the PV array, the site's weather data and solar radiation, estimated near and far shading issues, and estimated panel soiling issues.

This analysis included the installed cost of the PV system and, if applicable, financial incentives, and electrical upgrade cost. Additionally, this analysis considered the degradation in power production over time from the PV modules, string inverter replacement cost after ten (10) to twelve (12) years of operation, inflation rate, annual maintenance cost, and discount rate, among other variables. Usually for string inverters, the replacement cost is about 10% of the PV system installed cost.

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[34] Source: Funding Opportunities - Sustainable Communities Challenge Fund (nschallengefund.ca). Retrieved: 2024-07-31

[35] Source: Low Carbon Economy Challenge - Canada.ca. Retrieved: 2024-07-31

Two different PV system arrangements were assessed to determine which system shows the better financial performance, such as the lowest levelized cost of electricity and simple payback. The system was evaluated considering standard panels (monofacial) and bi-facial panels. These options include:

1. **Option A:** 144.7 kWp DC, 130 kW AC PV system with monofacial panels. Net metering.
2. **Option B:** 143.7 kWp DC, 130 kW AC PV system with bifacial panels. Net metering.

5.6.1 Financial Assumptions

The following list includes all the assumptions and variables considered for the technical and financial analysis of both roof and ground mounted PV systems.

- Solar PV modules capacity: monofacial 555 W; bifacial 550 W
- Inverter: String inverter
- PV panel orientation and angle: due south or southeast at a 40° angle for ground mounted and 30° angle for rooftop array, oriented southwest
- Roof mounted arrays were considered as monofacial for all options
- Building annual electricity consumption
- PV system modelled with software PVSyst
- General Inflation rate: 3%
- NSPI Electricity Inflation Rate: 4%
- O&M Inflation Rate: 4%
- Discount rate: 6.5%
- Interest rate: 6.5%
- Life of the project: 25 years
- Equity Ratio: 100% equity if capital <$150,000. If capital is >$150,000, consider $150,000 as equity and the rest as a loan, 20 year loan term if capital >$150,000.
- NS Power GHG emission intensity factor: 0.4506 CO2e kg/kWh in 2023[36]
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr
- String inverter replacement cost in year 12 (10% of CAPEX)

5.6.2 PV Systems Cost

Solar PV contractors in Nova Scotia were contacted to obtain budgetary installed costs for the proposed PV system arrangements, including Supernova Solar, Wattup Solar, and Natural Forces. It was determined that the average installed price for PV arrays with monofacial or standard panels is $2,175-3,000/kWp DC and with bifacial modules is $2,200-$3,075/kWp DC, depending on the system size, racking system, inverter technology (string versus microinverter), and PV installer. These budgetary installed costs do not include HST. This pricing excludes the costs for a geotechnical analysis and any required electrical upgrades and structural modifications to accommodate the new PV system.

[36] Source: https://www.nspower.ca/cleanandgreen/air-emissions-reporting. Retrieved: 2024-08-09

5.6.3 Geotechnical Analysis and Cost

Foundation designs of solar photovoltaic (PV) arrays commonly consist of ballasted footings founded at the ground surface (i.e., precast concrete pads), or anchored footings consisting of shallow, driven pile, or helical screw pile foundations embedded below ground. PV arrays also include supporting infrastructure such as service roads, storage shipping containers, electrical substations with transformers, concrete pads for electrical equipment, battery storage systems, etc. that each have their own unique foundation requirements.

Geotechnical investigations in support of PV arrays commonly consist of either test pit or borehole drilling investigations. The decision to excavate test pits versus drill boreholes is determined based on site specific requirements and considerations. A desktop study and site visit can help better define the geotechnical field investigation requirements. Underground utility locating should be completed prior to conducting the field investigations.

Geotechnical reports will often be structured in the following way:

- Introduction
- Project and Site Description
- Fieldwork Procedure
- Summarized Subsurface Conditions
- Discussions and Recommendations [including earthworks, foundation design for PVs and associated infrastructure (i.e., bearing capacity and settlement), slope stability, trenching, service roads, construction monitoring, etc.]

In-situ and laboratory testing on soils is conducted to characterize various index, strength, and environmental properties of the soils. This testing may include:

- Standard penetration testing (SPT)
- Moisture content
- Grain size analysis
- Proctor density
- Unconfined compressive strength (UCS) of rock
- Basic chemical testing relating to corrosion of buried concrete and steel including pH, sulphate, and chloride
- Thermal conductivity
- In-situ electrical resistivity
- Other in-situ strength tests as required
- Other environmental quality tests as required

5.6.3.1 Site Description

The site is located at the Falmouth Wastewater Treatment Plant, at 48 Falmouth Connector Road, Falmouth, NS. The site contains a wastewater treatment pond and associated infrastructure as shown in Figure 5.7 and Figure 5.8. The proposed locations of the PV arrays appear to be located on a cut slope and flat area near the south end of the site, and on a fill slope near the north end of the site. Both ballasted and anchored foundations are proposed as shown in Figure 5.7. The ballasted foundations are proposed due to potential underground piping at the south end of the site.

Based on geologic mapping, the principal soil unit in the area is ground moraine and streamlined drift till. The till is described as silty, compact, material derived from both local and distant sources[37].

Figure 5.7 - Ortho - 48 Falmouth Connector - Ballasted PV array area (yellow), anchored PV array (blue) (Eagleview, 2024)

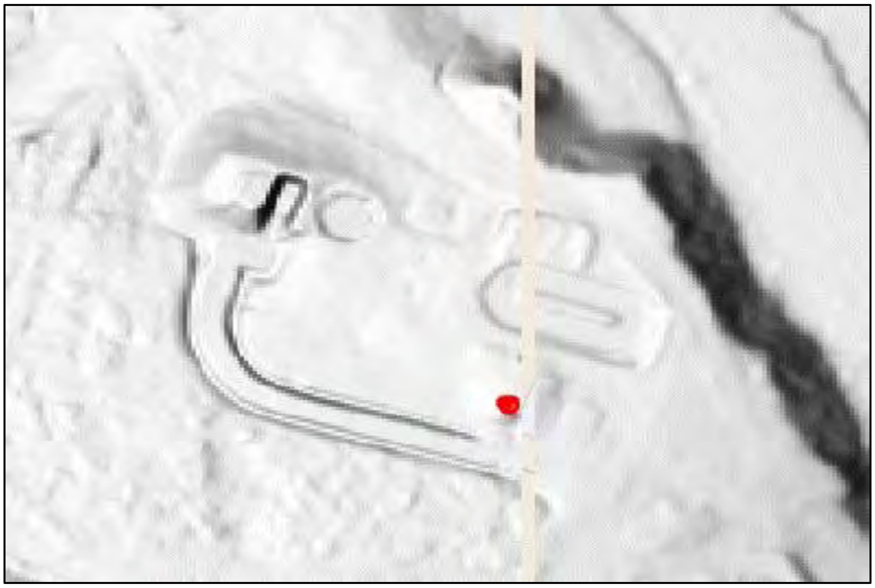

Figure 5.8 - LiDAR - 48 Falmouth Connector (GeoNOVA, 2024)

[37] Stea, R.R., Conley, H., Brown, Y. (1992). Surficial Geology of the Province of Nova Scotia – Map 92-3.

5.6.3.2 Potential Geotechnical Challenges

Potential geotechnical challenges include:

- Unknown fill materials at the site.
- Unknown placement and compaction method for fill materials at the site.
- Proximity to potential soft marine sediments.
- Mobilizing drill rig or excavator onto slopes.
- Slope stability.
- Bearing capacity.
- Differential settlement fill materials (if ballasted foundations are selected).
- Frost heave of fill materials (if ballasted foundations are selected).
- Misalignment of ballasted PVs due to settlement or frost heave (if ballasted foundations are selected).

5.6.3.3 Suggested Geotechnical Study

To support the PV array foundation design, the following geotechnical study is suggested:

- Geotechnical borehole investigation.
- Approximately 6 boreholes (2 at each proposed PV location).
- Approximately 3 monitoring wells to assist with groundwater level determination.
- Boreholes drilled to approximately 6 m.
- In-situ and laboratory testing and geotechnical report as described above in General Geotechnical Requirements.

5.6.3.4 Cost Estimate

The cost of the proposed geotechnical investigation would be in the range of $25k - $35k.

5.6.4 Electrical Analysis and Cost

For this site, interconnection with the main MCC is likely the most effective means of connecting the PV system. This location is primarily powered by a three-phase 600V distribution system.

In this option, the PV system size is restricted to the present energy consumption of the site. Therefore, no upgrade to the service entrance is required. A means of interconnecting the inverters with the existing distribution system will be required.

A system at 130kW would export 125A. This is too large to add to the 400A MCC, as it would become overloaded. We recommend installing a splitter and a 400A fused disconnect switch between the load terminal and the MCC. The other lugs on that splitter would be used to interconnect the PV system.

Per NSPI Bulletin B-64-200, a control system will be required to ensure the PV system shuts down upon loss of the utility interconnection.

Table 5.3: Electrical Work Cost Estimates

Item	Estimated Cost	Notes
Interconnection Wiring	$3,000	
600A Splitter, NEMA 1	$2,000	
1 x 150kVA Transformer, NEMA 3R	$20,000	Not required if the inverters could be connected at 600A
1 x 400A Disconnect Switch, complete with 400A Fuses	$3,000	
2 x 150A Disconnect Switch, complete with 150A Fuses	$5,000	
ATS Provisions	$1,500	
Total	**$33,000**	

5.6.5 Structural Upgrade Cost

Structural design drawings for the roof structure of the building were not available at the time of this review. The roof structure at this facility was observed to consist of prefabricated timber trusses typically spaced at 600 mm o/c. The timber trusses have plywood sheathing which is covered with asphalt shingles. The truss configuration varies depending on the location within the building. The attic space is accessible through a hatch but there does not appear to be a defined walkway. The attic also serves as a mechanical space with various pieces of mechanical equipment, ductwork, piping, etc. Generally, the timber trusses appeared to be supported on exterior timber or concrete masonry load bearing walls which in turn are likely supported on conventional concrete foundations and footings, however, the foundation walls were not visible above grade.

A cursory review of the prefabricated trusses with assumed loading for dead and snow load, both pre and post PV installation, indicates that the increase in stresses due to the weight from the addition of the proposed PV array would be in the order of 4%. Generally, during the design of timber trusses, member utilization has been observed to be in the order of 95%. A 4% increase in this utilization would be considered an acceptable increase. It was also noted that the intention is to replace the asphalt shingle roof of the structure in the near future (i.e., prior to potential PV installation) with metal roofing. Comparison of the roof loads before and after PV installation with the asphalt shingles removed and replaced with metal roofing results in an acceptable stress increase in the order of 3% and is the recommended approach.

In addition, the National Building Code for Canada (NBCC) 2020, which will be adopted by the Province of Nova Scotia soon, has new design considerations addressing the accumulation of snow drifts around PV systems. Depending on the final configuration of the array, it is possible that new snow drifting could be introduced. It is recommended that care be taken to place the array at the eaves of the roof and to ensure that the gaps between the panels are minimized and are no greater than the panel dimension. If these parameters cannot be met, snow drifts will accumulate which will be greater than the snow load considered in the original design of the trusses which will result in additional strengthening of the structure being required.

While strengthening of the truss members does not appear to be required, additional supports spanning between the trusses may be required to support the PV array connection, depending on the site-specific layout. It is recommended that the PV array be connected at a maximum spacing of 600 mm o/c to avoid locally overstressing the prefabricated truss members.

It is recommended that the racking support fastener extend into the truss or into members spanning between the trusses (depending on the layout). These additional members will offer additional anchor points. The estimated additional cost of adding these members to the roof structure is approximately $55,000. An estimate for the replacement of the roof is not included in this report as it is understood this work is already planned.

5.6.6 PV System – Net Metering

This PV system was sized considering that all the energy produced has to be consumed onsite and no surplus energy can be exported to the grid. This system would be equipped with a power production control system to monitor the building load to adapt the PV system production and to make sure there is no surplus energy sent back to the grid. The assumptions and variables considered for the financial analysis for Option 1 are the same for Option 2.

Figure 5.9 shows the 3D model in PVSyst and the area considered for the implementation of the PV system considering monofacial (Option A) and bifacial panels (Option B), respectively. The following items were considered when placing the PV system on this part of the property:

- No shading issues due to the proximity to nearby taller structures.
- Relatively flat surface.
- Proximity to the main building, which facilitates their interconnection.
- Excellent exposure to due south.
- Excellent visibility for the facility operators
- Easy access for maintenance.
- Racking system for PV system will be a combination of ballasted and anchored depending on the infrastructure underneath the PV array.

Figure 5.9: Roof and Ground Mounted PV Array

The estimated energy generation from the PVSyst model, as well as the estimated installed cost, current electricity rate, building annual energy consumption, and PV system specific production is included in Table 5.4. The PVSyst reports are included in Appendix B. Costs in the table below include HST.

Table 5.4: Roof and Ground Mounted PV System – Options A and B

Falmouth WWTP – Net Metering	Option A – 144.7 kWp DC Monofacial	Option B – 143.7 kWp DC Bifacial
Roof Top PV Capacity (kWp DC)	28.7	28.7
Roof Top PV Capacity (kWp AC)	30.0	30.0
Roof Top Installed Cost ($/kWp)	$2,362	$2,362
Roof Top Cost [PV only] ($)	$67,695	$67,695
Ground Mount PV Capacity (kWp DC)	116.0	115.0
Ground Mount PV Capacity (kWp AC)	100.0	100.0
Ground Mount Installed Cost ($/kWp)	$3,228	$3,275
Ground Mount Cost [PV only] ($)	$374,448	$376,625
Total Cost ($)	$442,143	$444,320
Installed Cost ($/kWp)	$3,056	$3,093
Electricity Rate ($/kWh)	$0.1479	$0.1479
Total PV Capacity (kWpDC)	144.7	143.7
Total PV Capacity (kWpAC)	130.0	130.0
Annual Consumption (kWh/yr)	448,051	448,051
Generated by PV and Consumed on Site (kWh/yr)	157,985	196,527

Falmouth WWTP – Net Metering	Option A – 144.7 kWp DC Monofacial	Option B – 143.7 kWp DC Bifacial
Generated by PV and Exported to Grid (kWh/yr)	28,455	1,324
PV Generation (kWh/yr)	186,440	197,851
PV Specific Production (kWh/yr/kWp)	1,289	1,377

When comparing the results considering monofacial panels (Option A) and bifacial panels (Option B), the following was observed:

- The installed cost per kWp for the ground mounted bifacial panels is approximately 1.4% higher than for monofacial panels.
- All electricity generated by the PV system would be either consumed on site or net metered to the grid.
- Surplus energy is not generated with the considered building energy consumption.
- Option A would provide 41.6% of the annual energy consumption.
- Option B would provide 44.2% of the annual energy consumption.
- All energy produced onsite will generate a cost savings at the same rate (NSPI electricity rate).
- The production and specific production from Option B (bifacial) is 5.8% and 6.4% higher than from Option A respectively, even though Option A kWp DC installed capacity is 0.7% larger than Option B.

In addition to these PV costs, other costs should be considered in the financial analysis. Table 5.5 shows the PV installation cost, as well as the electrical upgrade cost, geotechnical analysis, and design cost. As expected, the highest installation cost is for Option B, which also results in the highest total cost.

Table 5.5: PV Cost and Additional Costs - Options A and B

Installed Cost	Option A – 144.7 kWp DC Monofacial	Option B – 143.7 kWp DC Bifacial
PV Ground Mounted ($)	$374,448	$376,625
Geotechnical Analysis Cost ($)	$35,000	$35,000
Structural Upgrade Cost ($)	$55,000	$55,000
Electrical Upgrade Cost ($)	$33,000	$33,000
Design ($)	$48,650	$48,650
Total Project Cost ($)	**$546,098**	**$548,275**

Considering all these costs and the total savings, the following tables show the simple payback, net present value for a 25-year project horizon, life cycle costs (LCC), and the CO_2 emission reductions. Total savings include the energy savings and annual maintenance cost. Maintenance cost includes cleaning the panels twice a year, tightening the mechanical and electrical connections once a year, spot measurements once a year, and remote review of the system performance every three or four months.

Table 5.6: Financial Analysis – Options A and B

Falmouth WWTP	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option A – 144.7 kWp DC Monofacial	$546,098	$25,364	$27,574	21.5	-$100,589	-1.9	71.2
Option B – 143.7 kWp DC Bifacial	$548,275	$27,041	$29,262	20.3	-$73,027	-0.80	88.6

Option A results in lower installation cost but Option B has a higher total savings, which results in a shorter simple payback period for Option B. The cash flow and LCOE for both projects should be reviewed to further assess these options. The cash flow includes the maintenance cost and the savings from the generated electricity. Typically, a PV system fitted with string inverters requires the replacement of the inverters after ten (10) to twelve (12) years of operation, which results in a high maintenance cost in year 11 or 12.

5.6.6.1 Levelized Cost of Energy (LCOE)

The LCOE measures lifetime costs divided by energy production. It calculates the present value of the total cost of implementing and operating the building over an assumed lifetime. LCOE allows the comparison of different PV projects and different technologies (e.g., wind, solar, natural gas) of unequal life spans, project size, different capital cost, risk, return, and capacities. Figure 5.10 shows the LCOE formula.[38]

The LCOE calculation for this project considered the following variables:

- O&M Inflation rate: 4%
- Discount rate: 6.5%
- Life of the project: 25 years
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr (the same as in the previous section).
- Inverter replacement cost in year 12 (10% of CAPEX).

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

I_t = Investment expenditures in year t (including financing)
M_t = Operations and maintenance expenditures in year t
F_t = Fuel expenditures in year t
E_t = Electricity generation in year t
r = Discount rate
n = Life of the system

Figure 5.10: LCOE Formula

[38] Source: https://www.energy.gov/sites/prod/files/2015/08/f2/LCOE.pdf. Retrieved: 2020-02-05

Table 5.7 shows the costs included in the calculation of the LCOE and the estimated annual energy production factoring power production depreciation. The LCOE for Option A was determined to be $0.4811/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE of the purchase of electricity from the grid is $0.2151/kWh, which is lower than the LCOE for the PV system.

Table 5.7: LCOE Calculation – Option A

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000		-	-
1	-	$41,604	-$2,211	186,440
2	-	$41,604	-$2,299	184,576
3	-	$41,604	-$2,391	183,653
4	-	$41,604	-$2,487	182,734
5	-	$41,604	-$2,586	181,821
6	-	$41,604	-$2,690	180,912
7	-	$41,604	-$2,797	180,007
8	-	$41,604	-$2,909	179,107
9	-	$41,604	-$3,026	178,212
10	-	$41,604	-$3,147	177,320
11	-	$41,604	-$3,272	176,434
12	-	$41,604	-$47,618	175,552
13	-	$41,604	-$3,539	174,674
14	-	$41,604	-$3,681	173,801
15	-	$41,604	-$3,828	172,932
16	-	$41,604	-$3,981	172,067
17	-	$41,604	-$4,141	171,207
18	-	$41,604	-$4,306	170,351
19	-	$41,604	-$4,479	169,499
20	-	$41,604	-$4,658	168,651
21	-		-$4,844	167,808
22	-		-$5,038	166,969
23	-		-$5,239	166,134
24	-		-$5,449	165,304
25	-		-$5,667	164,477

The LCOE for Option B was determined to be $0.4552/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE of the purchase of electricity from the grid is $0.2151/kWh, which is lower than the LCOE for the PV system.

The LCOE for the NSPI grid was calculated considering inflation rate and the annual energy consumption of the building.

Table 5.8: LCOE Calculation – Option B

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000		-	-
1	-	$41,799	-$2,222	197,851
2	-	$41,799	-$2,310	195,872
3	-	$41,799	-$2,403	194,893
4	-	$41,799	-$2,499	193,919
5	-	$41,799	-$2,599	192,949
6	-	$41,799	-$2,703	191,984
7	-	$41,799	-$2,811	191,024
8	-	$41,799	-$2,923	190,069
9	-	$41,799	-$3,040	189,119
10	-	$41,799	-$3,162	188,173
11	-	$41,799	-$3,289	187,232
12	-	$41,799	-$47,852	186,296
13	-	$41,799	-$3,557	185,365
14	-	$41,799	-$3,699	184,438
15	-	$41,799	-$3,847	183,516
16	-	$41,799	-$4,001	182,598
17	-	$41,799	-$4,161	181,685
18	-	$41,799	-$4,327	180,777
19	-	$41,799	-$4,501	179,873
20	-	$41,799	-$4,681	178,974
21	-		-$4,868	178,079
22	-		-$5,063	177,188
23	-		-$5,265	176,302
24	-		-$5,476	175,421
25	-		-$5,695	174,544

Table 5.9 summarizes the results of the financial assessment for both options. Option B shows the highest NPV and lower LCOE compared to Option A.

Table 5.9: Summary - Financial Analysis - Options A and B

Falmouth WWTP	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	LCOE $/kWh	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option A – 144.7 kWp DC Monofacial	$546,098	$25,364	$0.4811	21.5	-$100,589	-1.9	71.2
Option B – 143.7 kWp DC Bifacial	$548,275	$27,041	$0.4552	20.3	-$73,027	-0.80	88.6

Considering that Option B was shown to have the highest NPV and lower LCOE compared to Option A, a sensitivity analysis around the total implementation cost was performed. Table 5.10 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

5.6.6.2 Sensitivity Analysis – CAPEX

A sensitivity analysis around the total implementation cost of Option B was performed. Table 5.10 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

Table 5.10: CAPEX Sensitivity Analysis

PV System	CAPEX Variance +/-%	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	LCOE ($/kWh)	Utility LCOE ($/kWh)
Option B – 144.7 kWp DC Bifacial	0%	$548,275	$28,623	$30,845	20.3	-$73,027	-0.8	$0.4552	$0.2151
	30%	$712,758			26.4	-$274,504	-6.3	$0.6073	$0.2151
	-20%	$438,620			16.2	$61,291	3.4	$0.3538	$0.2151

5.6.6.3 Sensitivity Analysis – Energy Generation

A sensitivity analysis around the total energy generation was performed. Table 5.11 shows what the simple payback and LCOE range would be if the electricity generation varied between -5% and +5%.

Table 5.11: Sensitivity Around kW/yr Generation

PV System	+/- % kWh/yr	kWh/yr	Total Savings ($/yr)	Simple Payback (yr)	LCOE $/kWh	Utility LCOE ($/kWh)
Option B – 144.7 kWp DC Bifacial	-	197,851	$27,041	20.3	$0.4552	$0.2151
	-5%	187,958	$25,577	21.4	$0.4792	$0.2151
	5%	207,744	$28,504	19.2	$0.4335	$0.2151

5.7 PV Project Estimated Timeline

The implementation of any of these projects will require the completion of a number of tasks. Considering that an engineering company produces the design and tender package, and a solar PV contractor installs the system (turn-key project), a project timeline was estimated. The tables below depict the estimated timeline to complete the options described for this site.

Table 5.12: Estimated Timeline for Options A and B

Task #	Option 1 and 2 - Tasks – 116 kWp Monofacial and 115 kWp Bifacial PV Systems	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
1	RFP process to design and create the tender package for the PV system. Select PV designer. If WHRM requires an Engineer to act as Owner's Engineer, an RFP to select it could occur in parallel to the RFP to select the PV designer.	6	6	weeks after RFP was issued
2	PV Designer: Kick-off Meeting, Available Information Review	1	7	weeks after RFP was issued
3	PV Designer: Site Visit	1	8	weeks after RFP was issued
4	PV Designer: PV System Design and Tender Package Preparation	8	16	weeks after RFP was issued
5	WHRM: Design and Tender Package Review	1	17	weeks after RFP was issued
6	PV Designer: Design and Tender Package Update According to WHRM Comments	1	18	weeks after RFP was issued
7	WHRM: Tender Package Is Issued	1	19	weeks after RFP was issued
8	Bidders: Tender Period, Question and Answer Period. Bids are submitted to WHRM.	4	23	weeks after RFP was issued
9	WHRM or Owner's Engineer: Bid Assessment, Question and Answer with bidders, Bids	3	26	weeks after RFP was issued

Task #	Option 1 and 2 - Tasks – 116 kWp Monofacial and 115 kWp Bifacial PV Systems	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
	Ranking and Recommendation. Successful bidder is contacted.			
10	WHRM: Negotiation with Successful Bidder. Contract signing.	2	28	weeks after RFP was issued
11	PV Contractor: Kick-off Meeting, Available Information Review, Site Visit.	2	30	weeks after RFP was issued
12	PV Contractor: Equipment Selection and Acquisition. PV System Installation.	14	44	weeks after RFP was issued
13	WHRM or Owner's Engineer: Design drawings and Shop Drawings Review. Site visits. Communications with PV Contractor (in parallel to above)	14	44	weeks after RFP was issued
14	PV Contractor: System Start-up	1	45	weeks after RFP was issued
15	WHRM or Owner's Engineer: As-built Document and Drawings Review. System Commissioning. Commissioning Report.	4	49	weeks after RFP was issued

6 3 Lagoon Drive – Windsor Wastewater Treatment Plant "Old Lagoons"

6.1 Review of Historic Energy Performance

The Windsor Wastewater Treatment plant located at 3 Lagoon Drive in Windsor, NS, provided electricity bills for a 24 month period spanning January 2022 to December 2023. Energy consumption and demand were reviewed in annual terms to ensure that variation in seasonality was observable. With at least two periods available, a month-to-month comparison of the facility's energy performance was made from one year to the next. Review of electricity consumption profiles based on the information obtained from the two periods was discussed and is compared in this section. This review will also include observed variations in electricity demand by month across the two annual periods.

6.1.1 Electricity Use Profiles

Figure 6.1 provides the bi-monthly electricity usage profile which shows the 24-month period from January 2022 to December 2023.

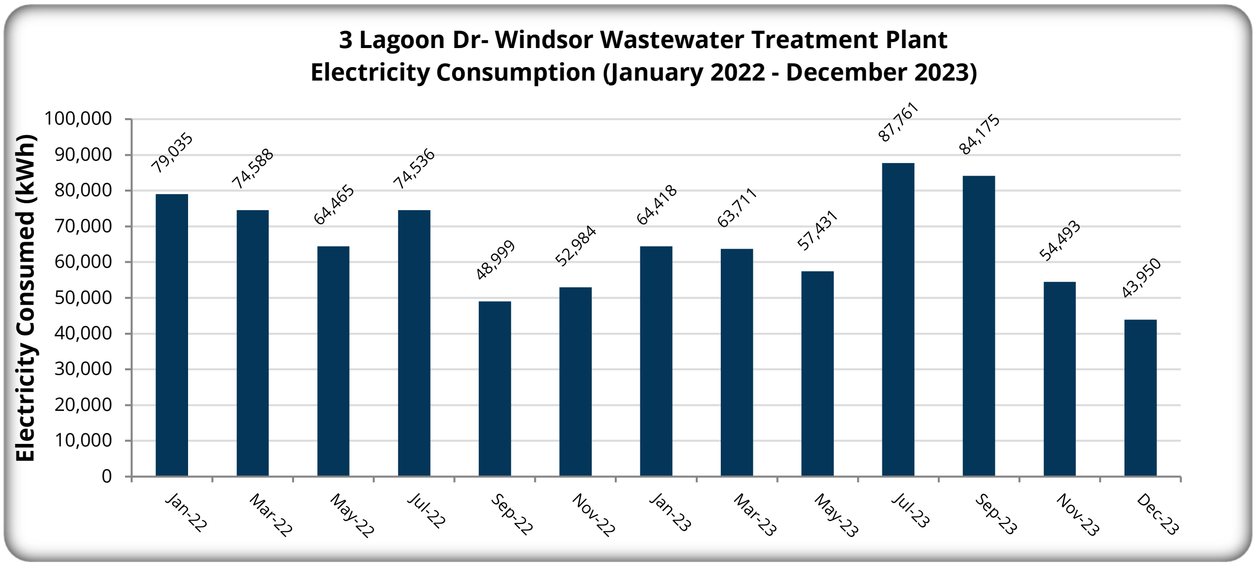

Figure 6.1: 2022/2023 Monthly Electricity Consumption

Figure 6.1 depicts a trend that shows a higher electricity consumption in the summer months, which is most likely due to the demand for air-conditioning in the building. Total electricity usage in the period January 2022/December 2022 was 394,607 kWh and 455,939 kWh in the January 2023/December 2023 year. The average annual energy consumption considering these two 12-month periods is 425,273 kWh.

Facility electricity demand was reviewed for each of the months between January 2022 and December 2023. Figure 6.2 presents a bi-monthly peak demand trend for this 24-month period.

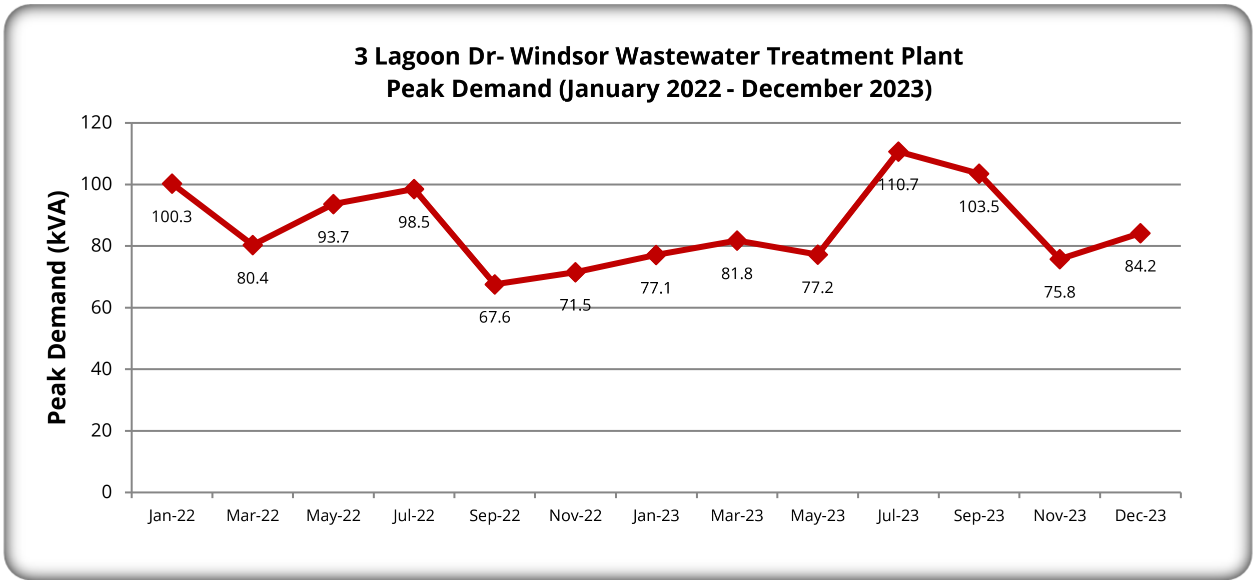

Figure 6.2: Bimonthly Electricity Peak Demand over 24 Consecutive Months

Figure 6.2 shows a trend that closely follows the kWh consumption. The higher peak demand occurred in the summer months, as this is a wastewater treatment facility demand consumption would be tied to the amount of effluent that needs to be processed. The monthly peak demand ranges between 67.6 kVA and 110.7 kVA. The highest demand peak was recorded at 110.7 kVA in the billing period spanning from May-July 2023 while the lowest demand occurred in the billing period between July-September 2021 at 67.6kW.

6.1.2 Electricity Cost

Electricity is provided by the Nova Scotia Power as a “Small Industrial Tariff” electricity rate[39].

[39] Source: Small Industrial Tariff| Nova Scotia Power (nspower.ca). Retrieved: 2024-07-22

SMALL INDUSTRIAL TARIFF

Availability

This tariff is applicable to electric power and energy supplied to any customer, for industrial use, including farming and processing, where the regular billing demand is less than 250 kV.A or 225 kW.

Demand Charge

$8.332 per month per kilovolt ampere of maximum demand

Energy Charge

14.05¢ per kilowatt hour for the first 200 kilowatt hours per month per kilovolt ampere of maximum demand
11.476¢ per kilowatt hour for all additional kilowatt hours

Figure 6.3: NSPI Small Industrial Tariff Rate

The electricity consumption breakdown is depicted in Figure 6.4. This shows that the kWh cost represents about 84.0% and 84.3% of the cost in the monthly power bills in 2022 and 2023, respectively. Monthly electricity cost closely follows the monthly kWh consumption. Total electricity cost in the period January 2022/December 2022 was $41,443 and $50,738 in the January 2023/December 2023 period. The average annual electricity cost considering this two 12-month periods is $54,766. Also, the average unit cost of electricity, considering all costs in the bills, was $0.1288/kWh (not including HST) over the 24-month period provided.

An estimated electricity (kWh only) rate for 2024 of $0.1399/kWh was calculated by applying 2024 NSPI Commercial General Tariff rates to 2023 electricity consumption and peak demand values. A 15% HST was also applied. This average kWh rate does not include the additional demand charge, as the implementation of PV to the facility will not reduce the facility's peak demand.

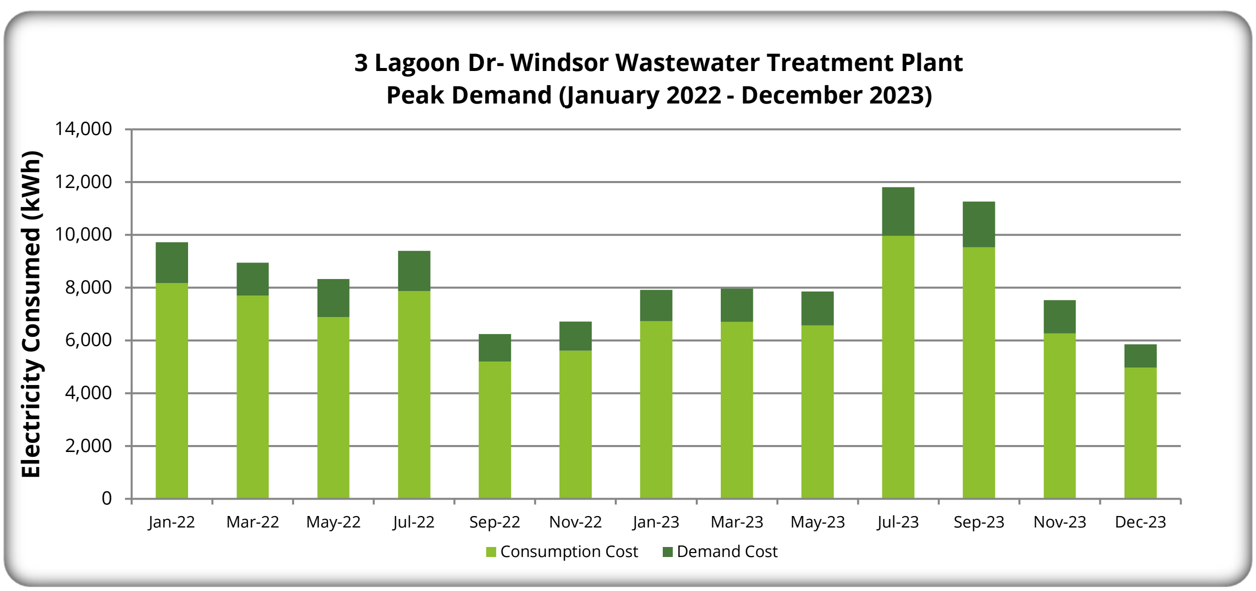

Figure 6.4: Electricity Cost Breakdown

Table 6.1 shows the monthly power bill cost breakdown for the January 2022 to December 2023 24-month period.

Table 6.1: Monthly Power Bill Cost Breakdown for the January 2022 to December 2023

Billing Period		Consumption (kWh)	Consumption Cost ($)	Peak Demand (kVA)	Demand Cost ($)	Invoice Amount ($)
Start Date	End Date					
22-Nov-21	21-Jan-22	79,035	$8,170.37	100.3	$1,547.43	$9,717.80
22-Jan-22	23-Mar-22	74,588	$7,703.05	80.4	$1,240.41	$8,943.46
24-Mar-22	20-May-22	64,465	$6,888.40	93.7	$1,445.60	$8,334.00
21-May-22	21-Jul-22	74,536	$7,870.75	98.5	$1,519.66	$9,390.41
22-Jul-22	21-Sep-22	48,999	$5,201.27	67.6	$1,042.93	$6,244.20
22-Sep-22	22-Nov-22	52,984	$5,609.05	71.5	$1,103.10	$6,712.15
23-Nov-22	23-Jan-23	64,418	$6,725.79	77.1	$1,189.50	$7,915.29
24-Jan-23	23-Mar-23	63,711	$6,704.84	81.8	$1,262.01	$7,966.85
24-Mar-23	23-May-23	57,431	$6,572.99	77.2	$1,286.46	$7,859.45
24-May-23	21-Jul-23	87,761	$9,969.40	110.7	$1,844.70	$11,814.10
22-Jul-23	20-Sep-23	84,175	$9,534.48	103.5	$1,724.72	$11,259.20
21-Sep-23	22-Nov-23	54,493	$6,262.98	75.8	$1,263.13	$7,526.11
23-Nov-23	31-Dec-23	43,950	$4,967.14	84.2	$882.60	$5,849.74

6.1.3 Total Energy Use Summary

The facility's total energy usage is shown in Table 6.2. The average for the 24-month period considers the electricity consumption records for January 2022 to December 2023.

Table 6.2: Energy Use Summary

Windsor Wastewater Treatment Plant "Old Lagoons"	2022	2023
Electricity		
Annual Electricity and Demand Cost ($)	$49,342	$60,191
Annual Electricity Consumption (kWh)	394,607	455,939
Annual Electricity Consumption (GJ)	1,420.6	1,641.4
Cost per GJ ($/GJ)	$34.73	$36.67
Percentage of Total Energy (%)	100.0%	100.0%
GHG Emissions (tCO_2/yr)	219.9	205.4
kWh Cost w/o Demand + HST to be used for Cost Savings Estimations ($/kWh)	$0.1399/kWh	

6.2 NSPI Net Metering Program

The Net Metering Program offered by NSPI provides an incentive for on-site renewable power generation. Using a 2-way meter, NSPI records the amount of power consumed by the facility, as well as any surplus power which is generated on-site using renewable technologies and returned to the grid. NSPI then charges the customer for the difference between energy consumed and energy returned to the grid.

NSPI allows the installation of PV systems of a minimum size of 27kW AC up to a maximum 1000kW AC array for net metering if the NSPI customer has a demand meter which this facility does. If the facility does not have a demand meter, of it is not a winery, farm, or licensed aquaculture plant, the facility could have a PV system with a capacity between 27 and 200 kW AC. If the facility owner has multiple accounts with NSPI, the PV system can supply electricity to other accounts owned by the same person/institution as long as they are within the same geographical area known as NSPI distribution zone.

Annual PV production cannot be higher than the building's annual electricity consumption to qualify for net metering[40].

6.3 Considerations to Size the PV System

The 3 Lagoon Drive Wastewater Treatment Plant site consumes over 420,000 kWh/yr which makes it a good candidate for a solar PV system with a capacity of about 330 kW (DC). This is the maximum capacity allowed by NSPI for a client that wants to participate in the net metering program. A 330 kW (DC) PV array in Nova Scotia will produce, on average 410,000 kWh (AC) per year, well below the building's annual consumption, thus making the building eligible for the net metering program. The net metering program will permit surplus energy generated from the array to be transferred to the NSPI grid via a bi-directional meter that will record the amount of energy transferred to the grid and credit that amount against future consumption from the grid. This system allows for all energy generated by the array to be used productively without the need or expense of an onsite energy storage system.

6.4 PV System

6.4.1 Ground Mounted

The ground mounted PV system can be located on the area west of the building. Water wells and any other infrastructure should be considered when sizing a solar PV array. A typical ground mounted system is shown in Figure 6.5. The implementation of this type of racking system will typically require a geotechnical analysis of the

Figure 6.5: Typical Ground Mounted PV Array

[40] Source: Commercial Net Metering| Nova Scotia Power (nspower.ca). Retrieved: 2024-07-31

site to be able to design the array foundations. Also, a ballasted PV system can be implemented, which does not require foundations to anchor the racking to the ground. Site conditions are sufficiently typical to permit a standard foundation design for this size of array to be used for this level of analysis. The cost of geotechnical analysis, as part of the detailed system design cost, is included in the capital cost estimate for this array. Also, alternative mounts such as single or dual axis tracking were not considered due to the additional maintenance requirements.

6.5 Incentive Programs

6.5.1 Low Carbon Communities Program

West Hants Regional Municipality may be eligible for the *Low Carbon Communities Program.* The program offers funding to recover up to 75% of the total project costs to a maximum of $75,000. The program provides 90% of the funding at the start of the project and the remaining 10% when the project is completed and the final reports submitted. No more than 75% of the total project cost can be funded through the provincial government[41]. This program requires that reduction in GHG emissions be demonstrated. The expected reductions in capital cost for this project, due to this incentive program, are included in the financial analysis. Further details about the requirements from this program can be found here: Low Carbon Communities - Government of Nova Scotia, Canada. The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

6.5.2 Green Municipal Fund: Local Energy Generation

West Hants Regional Municipality may be eligible for the Green Municipal Fund's *Community Energy Systems: Capital Projects* grant and loan program. The program offers a combined grant and loan up to 80% of eligible project costs to a maximum of $10,000,000. With the grant being eligible for up to 15% of project costs. This program requires the completion of a feasibility study which considers technical and financial, as well as the social and environmental impacts of the project[42]. Further details about the requirements from this program can be found here: Capital project: Community Energy Systems (greenmunicipalfund.ca).

6.5.3 Sustainable Communities Challenge Fund

West Hants Regional Municipality may be eligible for the *Sustainable Communities Challenge Fund: Mitigation Stream*. This fund provides grants up to 80% of eligible projects costs to a maximum of $1,000,000. The applicant must supply a minimum of 20% of eligible project costs, which may be made by alternate funding sources such as federal funding sources.

[41] Source: Low Carbon Communities - Government of Nova Scotia, Canada. Retrieved: 2024-07-31
[42] Source: Capital project: Community Energy Systems (greenmunicipalfund.ca). Retrieved: 2024-07-31

This program requires that reduction in GHG emissions be demonstrated[43]. Further details about the requirements from this program can be found here: Funding Opportunities - Sustainable Communities Challenge Fund (nschallengefund.ca). The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

6.5.4 Low Carbon Economy Challenge

West Hants Regional Municipality may be eligible for the *Low Carbon Economy*. This fund provides grants up to 50% of eligible projects costs for provincial municipalities. The fund ranges from a minimum of $1,000,000 to a maximum of $25,000,000 in available funding. According to the program, the project must produce electricity for the facility's own use. Eligible projects must result in a reduction in GHG emissions. Further details about the requirements from this program can be found here: Low Carbon Economy Challenge Applicant Guide 2023 - Canada.ca.[44] The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

6.6 Technical-Financial and Life Cycle Analyses

The sizing and estimation of energy production from the PV system was completed with the modelling software PVSyst, which is one of the most recognized PV modelling software platforms in the world. The PVSyst model considered the building's load profile or energy consumption, the exact location of the PV array, the site's weather data and solar radiation, estimated near and far shading issues, and estimated panel soiling issues.

This analysis included the installed cost of the PV system and, if applicable, financial incentives, and electrical upgrade cost. Additionally, this analysis considered the degradation in power production over time from the PV modules, string inverter replacement cost after ten (10) to twelve (12) years of operation, inflation rate, annual maintenance cost, and discount rate, among other variables. Usually for string inverters, the replacement cost is about 10% of the PV system installed cost.

Two different PV system arrangements were assessed to determine which system shows the better financial performance, such as the lowest levelized cost of electricity and simple payback. The system was evaluated considering standard panels (monofacial) and bi-facial panels. These options include:

1. **Option A:** 308 kWp DC, 275 kW AC PV system with monofacial panels. Net metering.
2. **Option B:** 279 kWp DC, 250 kW AC PV system with bifacial panels. Net metering.

[43] Source: Funding Opportunities - Sustainable Communities Challenge Fund (nschallengefund.ca). Retrieved: 2024-07-31

[44] Source: Low Carbon Economy Challenge - Canada.ca. Retrieved: 2024-07-31

6.6.1 Financial Assumptions

The following list includes all the assumptions and variables considered for the technical and financial analysis of both roof and ground mounted PV systems.

- Solar PV modules capacity: monofacial 555 W; bifacial 550 W
- Inverter: String inverter
- PV panel orientation and angle: due south or slightly southwest at a 40° angle for ground mounted
- Building annual electricity consumption
- Roof mounted arrays were considered as monofacial for all options.
- PV system modelled with software PVSyst
- General Inflation rate: 3%
- NSPI Electricity Inflation Rate: 4%
- O&M Inflation Rate: 4%
- Discount rate: 6.5%
- Interest rate: 6.5%
- Life of the project: 25 years
- Equity Ratio: 100% equity if capital <$150,000. If capital is >$150,000, consider $150,000 as equity and the rest as a loan, 20 year loan term if capital >$150,000.
- NS Power GHG emission intensity factor: 0.4506 CO2e kg/kWh in 2023[45]
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr
- String inverter replacement cost in year 12 (10% of CAPEX)

6.6.2 PV Systems Cost

Solar PV contractors in Nova Scotia were contacted to obtain budgetary installed costs for the proposed PV system arrangements, including Supernova Solar, Wattup Solar, and Natural Forces. It was determined that the average installed price for PV arrays with monofacial or standard panels is $2,175-3,000/kWp DC and with bifacial modules is $2,200-$3,075/kWp DC, depending on the system size, racking system, inverter technology (string versus microinverter), and PV installer. These budgetary installed costs do not include HST. This pricing excludes the costs for a geotechnical analysis and any required electrical upgrades and structural modifications to accommodate the new PV system.

6.6.3 Geotechnical Analysis and Cost

Foundation designs of solar photovoltaic (PV) arrays commonly consist of ballasted footings founded at the ground surface (i.e., precast concrete pads), or anchored footings consisting of shallow, driven pile, or helical screw pile foundations embedded below ground. PV arrays also include supporting infrastructure such as service roads, storage

[45] Source: https://www.nspower.ca/cleanandgreen/air-emissions-reporting. Retrieved: 2024-08-09

shipping containers, electrical substations with transformers, concrete pads for electrical equipment, battery storage systems, etc. that each have their own unique foundation requirements.

Geotechnical investigations in support of PV arrays commonly consist of either test pit or borehole drilling investigations. The decision to excavate test pits versus drill boreholes is determined based on site specific requirements and considerations. A desktop study and site visit can help better define the geotechnical field investigation requirements. Underground utility locating should be completed prior to conducting the field investigations.

Geotechnical reports will often be structured in the following way:

- Introduction
- Project and Site Description
- Fieldwork Procedure
- Summarized Subsurface Conditions
- Discussions and Recommendations [including earthworks, foundation design for PVs and associated infrastructure (i.e., bearing capacity and settlement), slope stability, trenching, service roads, construction monitoring, etc.]

In-situ and laboratory testing on soils is conducted to characterize various index, strength, and environmental properties of the soils. This testing may include:

- Standard penetration testing (SPT)
- Moisture content
- Grain size analysis
- Proctor density
- Unconfined compressive strength (UCS) of rock
- Basic chemical testing relating to corrosion of buried concrete and steel including pH, sulphate, and chloride
- Thermal conductivity
- In-situ electrical resistivity
- Other in-situ strength tests as required
- Other environmental quality tests as required

6.6.3.1 Site Description

The site is located at the Windsor Wastewater Treatment Plant, at 3 Lagoon Drive, Windsor, NS. The site contains two wastewater treatment ponds as shown in Figure 6.6 and Figure 6.7. The ponds are encircled by berms built up above the existing grade. The height and geometry of the berms is unknown at this time, but it is assumed that the berms are at least 2-3 m tall, with a minimum of 2 horizontal to 1 vertical (2H:1V) side slopes. The fill material used to construct the berms is unknown at this time. The PV arrays are proposed to be located on the berms. Both ballasted and anchored foundations are proposed.

Based on geologic mapping, the principal soil unit in the area is ground moraine and streamlined drift till. The till is described as silty, compact, material derived from both local and distant sources[46].

Figure 6.6: Ortho - 3 Lagoon Drive - Ballasted PV array area (yellow), anchored PV array (blue) (GoogleEarth, 2024)

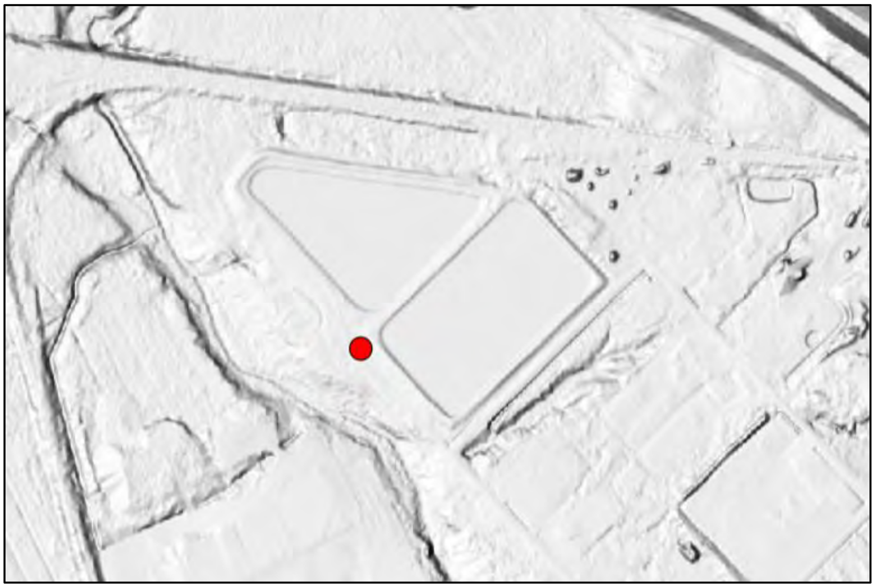

Figure 6.7: LiDAR - 3 Lagoon Drive (GeoNOVA, 2024)

6.6.3.2 Potential Geotechnical Challenges

Potential geotechnical challenges include:

- Unknown berm fill material.

[46] Stea, R.R., Conley, H., Brown, Y. (1992). Surficial Geology of the Province of Nova Scotia – Map 92-3.

- Unknown placement and compaction methods of berm fill material.
- Slope stability.
- Bearing capacity.
- Differential settlement of berm fill materials (if ballasted foundations are selected).
- Frost heave of berm fill materials (if ballasted foundations are selected).
- Damage to the liner of the lagoons during investigation and construction (liner is likely keyed into the crest of the berms).
- Access to toe of berms due to proximity to treeline.
- Damage to the crest and slope of the lagoons during construction.
- Unknown location of lagoon piping etc.
- Restricted access to crest of berms.
- Restricted view and access of downstream side of the lagoon berms that may impede routine maintenance and surveillance.
- Misalignment of ballasted PVs due to settlement or frost heave.
- PV system wiring may need to run through the above-ground conduits and not in underground trenches to preserve berm stability.

6.6.3.3 Suggested Geotechnical Study

To support the PV array foundation design, the following geotechnical study is suggested:

- Geotechnical borehole investigation.
- Approximately 12 boreholes drilled at 50 m increments along the berm crest.
- Approximately 3 monitoring wells to assist with groundwater level determination.
- Boreholes to be drilled through berm fill materials into competent native soils. Estimated depth is approximately 5-6 m.
- In-situ and laboratory testing and geotechnical report as described above in General Geotechnical Requirements.

6.6.3.4 Cost Estimate

The cost of the proposed geotechnical investigation would be in the range of $30k - $40k.

6.6.4 Electrical Analysis and Cost

For this site, interconnection with the main MCC is likely the most effective means of connecting the PV system. This location is primarily powered by a three-phase 600V distribution system.

In this option, the PV system size is restricted to the present energy consumption of the site. Therefore, no upgrade to the service entrance is required. A means of interconnecting the inverters with the existing distribution system will be required.

A system at 275kW would export 264A. This is too large to add to the MCC, as it would become overloaded. We recommend installing a splitter and a 300A fused disconnect switch between the load terminal and the MCC. The other lugs on that splitter would be used to interconnect the PV system.

Per NSPI Bulletin B-64-200, a control system will be required to ensure the PV system shuts down upon loss of the utility interconnection.

Table 6.3: Estimated Electrical Work Cost

Item	Estimated Cost	Notes
Interconnection Wiring	$3,000	
600A Splitter, NEMA 1	$2,000	
1 x 175kVA Transformer, NEMA 3R	$25,000	Not required if the inverters could be connected at 600A
1 x 400A Disconnect Switch, complete with 400A Fuses	$3,000	
2 x 300A Disconnect Switch, complete with 300A fuses	$5,000	
Total	**$38,000**	**N/A**

6.6.5 PV System – Net Metering

This PV system was sized considering that all the energy produced has to be consumed onsite and no surplus energy can be exported to the grid. This system would be equipped with a power production control system to monitor the building load to adapt the PV system production and to make sure there is no surplus energy sent back to the grid.

Figure 6.8 shows the 3D models in PVSyst and the area considered for the implementation of the PV system considering monofacial (Option A) and bifacial panels (Option B). The following items were considered when placing the PV system on this part of the property:

- No shading issues due to the proximity to nearby taller structures.
- Relatively flat surface.
- Proximity to the main building, which facilitates their interconnection.
- Excellent exposure to due south.
- Excellent visibility for the facility operators.
- Easy access for maintenance.
- Set back of about 20 m was allows between the parking lot, helipad and the PV system for snow accumulation.
- Racking system for PV system will be a combination of ballasted and anchored depending on proximity to the lagoon PV array.

Figure 6.8: Ground Mounted PV Array – Option A and B

The estimated energy generation from the PVSyst model, as well as the estimated installed cost, current electricity rate, building annual energy consumption, and PV system specific production is included in Table 6.4. The PVSyst reports are included in Appendix B. Costs in the table below include HST.

Table 6.4: Ground Mounted PV System – Options A and B

3 Lagoon Dr–Net Metering	Option A – 308 kWp DC Monofacial	Option B – 279 kWp DC Bifacial
Ground Mount PV Capacity (kWp DC)	308.0	279.0
Ground Mount PV Capacity (kWp AC)	275.0	250.0
Ground Mount Installed Cost ($/kWp)	$3,073	$3,119
Ground Mount Cost [PV only] ($)	$946,484	$870,201
Installed Cost ($/kWp)	$3,073	$3,119
Electricity Rate ($/kWh)	$0.1399	$0.1399
Annual Consumption (kWh/yr)	425,273	425,273
Generated by PV and Consumed on Site (kWh/yr)	153,216	155,182
Generated by PV and Exported to Grid (kWh/yr)	251,114	240,283
PV Generation (kWh/yr)	404,329	395,465
PV Specific Production (kWh/yr/kWp)	1,313	1,417

When comparing the results considering monofacial panels (Option A) and bifacial panels (Option B), the following was observed:

- The installed cost per kWp for bifacial panels is approximately than 1.5% higher than for monofacial panels.
- All electricity generated by the PV system would be consumed onsite.

- Surplus energy is not generated with the considered building energy consumption.
- Option A would provide 95.1% of the annual energy consumption.
- Option B would provide 93.0% of the annual energy consumption.
- All the energy produced onsite will generate a cost savings at the same rate (NSPI electricity rate).
- The production and specific production from Option B (bifacial) is 2.2% lower and 7.9% higher than from Option A, respectively. Option B's kWp DC installed capacity is 9.4% lower than Option A.

In addition to these PV costs, other costs should be considered in the financial analysis. Table 6.5 shows the PV installation cost, as well as the electrical upgrade cost, geotechnical analysis, and design cost. As expected, the highest installation cost is for Option A, which also results in the highest total cost.

Table 6.5: PV Cost and Additional Costs - Options A and B

Installed Cost	Option A - 308 kWp DC Monofacial	Option B - 279 kWp DC Bifacial
PV Ground Mounted ($)	$946,484	$870,201
Geotechnical Analysis Cost ($)	$40,000	$40,000
Electrical Upgrade Cost ($)	$38,000	$38,000
Design ($)	$52,100	$52,100
Total Project Cost ($)	**$1,076,584**	**$1,000,301**

Considering all these costs and the total savings, the following tables show the simple payback, net present value for a 25-year project horizon, life cycle costs (LCC), and the CO_2 emission reductions. Total savings include the energy savings and annual maintenance cost. Maintenance cost includes cleaning the panels twice a year, tightening the mechanical and electrical connections once a year, spot measurements once a year, and remote review of the system performance every three or four months.

Table 6.6: Financial Analysis – Options A and B

Windsor Wastewater Treatment Plant	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option A - 308 kWp DC Monofacial	$1,076,584	$51,833	$56,566	20.8	-$108,699	1.1	69.0
Option B - 279 kWp DC Bifacial	$1,000,301	$50,975	$0.3904	19.6	-$45,214	2.2	69.9

Option B has a lower cost savings per year, but also has a lower installation cost, which results in a shorter simple payback than Option A. The cash flow and LCOE for both projects should be reviewed to further assess these options. The cash flow includes the maintenance cost and the savings from the generated electricity. Typically, a PV system fitted with string inverters requires the replacement of the inverters after ten (10) to twelve (12) years of operation, which results in a high maintenance cost in year 11 or 12.

6.6.5.1 Levelized Cost of Energy (LCOE)

The LCOE measures lifetime costs divided by energy production. It calculates the present value of the total cost of implementing and operating the building over an assumed lifetime. LCOE allows the comparison of different PV projects and different technologies (e.g., wind, solar, natural gas) of unequal life spans, project size, different capital cost, risk, return, and capacities. Figure 6.9 shows the LCOE formula.[47]

The LCOE calculation for this project considered the following variables:

- O&M Inflation rate: 4%
- Discount rate: 6.5%
- Life of the project: 25 years
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr (the same as in the previous section).
- Inverter replacement cost in year 12 (10% of CAPEX).

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

I_t = Investment expenditures in year t (including financing)
M_t = Operations and maintenance expenditures in year t
F_t = Fuel expenditures in year t
E_t = Electricity generation in year t
r = Discount rate
n = Life of the system

Figure 6.9: LCOE Formula

Table 6.7 shows the costs included in the calculation of the LCOE and the estimated annual energy production factoring power production depreciation. The LCOE for Option A was determined to be $0.4132/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE of the purchase of electricity from the grid is $0.2035/kWh, which is lower than the LCOE for the PV system.

[47] Source: https://www.energy.gov/sites/prod/files/2015/08/f2/LCOE.pdf. Retrieved: 2020-02-05

Table 6.7: LCOE Calculation – Option A

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000		-	-
1	-	$83,118	-$4,732	404,329
2	-	$83,118	-$4,922	400,286
3	-	$83,118	-$5,119	398,284
4	-	$83,118	-$5,323	396,293
5	-	$83,118	-$5,536	394,311
6	-	$83,118	-$5,758	392,340
7	-	$83,118	-$5,988	390,378
8	-	$83,118	-$6,228	388,426
9	-	$83,118	-$6,477	386,484
10	-	$83,118	-$6,736	384,552
11	-	$83,118	-$7,005	382,629
12	-	$83,118	-$101,934	380,716
13	-	$83,118	-$7,577	378,812
14	-	$83,118	-$7,880	376,918
15	-	$83,118	-$8,195	375,034
16	-	$83,118	-$8,523	373,158
17	-	$83,118	-$8,864	371,293
18	-	$83,118	-$9,218	369,436
19	-	$83,118	-$9,587	367,589
20	-	$83,118	-$9,970	365,751
21	-		-$10,369	363,922
22	-		-$10,784	362,103
23	-		-$11,215	360,292
24	-		-$11,664	358,491
25	-		-$12,131	356,698

The LCOE for Option B was determined to be $0.3904/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE of the purchase of electricity from the grid is $0.2035/kWh, which is lower than the LCOE for the PV system. The LCOE for the NSPI grid was calculated considering inflation rate and the annual energy consumption of the building.

Table 6.8: LCOE Calculation – Option B

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000		-	-
1	-	$76,275	-$4,351	395,465
2	-	$76,275	-$4,525	391,510
3	-	$76,275	-$4,706	389,553
4	-	$76,275	-$4,894	387,605
5	-	$76,275	-$5,090	385,667
6	-	$76,275	-$5,294	383,739
7	-	$76,275	-$5,505	381,820
8	-	$76,275	-$5,726	379,911
9	-	$76,275	-$5,955	378,011
10	-	$76,275	-$6,193	376,121
11	-	$76,275	-$6,441	374,241
12	-	$76,275	-$93,718	372,369
13	-	$76,275	-$6,966	370,508
14	-	$76,275	-$7,245	368,655
15	-	$76,275	-$7,535	366,812
16	-	$76,275	-$7,836	364,978
17	-	$76,275	-$8,149	363,153
18	-	$76,275	-$8,475	361,337
19	-	$76,275	-$8,814	359,530
20	-	$76,275	-$9,167	357,733
21	-		-$9,534	355,944
22	-		-$9,915	354,164
23	-		-$10,312	352,394
24	-		-$10,724	350,632
25	-		-$11,153	348,878

Table 6.9 summarizes the results of the financial assessment for both options. Option B shows the highest NPV and lower LCOE compared to Option A.

Table 6.9: Summary - Financial Analysis - Options A and B

Windsor Wastewater Treatment Plant	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	LCOE $/kWh	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option A - 308 kWp DC Monofacial	$1,076,584	$51,833	$0.4132	20.8	-$108,699	1.1	69.0

Windsor Wastewater Treatment Plant	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	LCOE $/kWh	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option B - 279 kWp DC Bifacial	$1,000,301	$50,975	$0.3904	19.6	-$45,214	2.2	69.9

Considering that Option B was shown to have the highest NPV and lower LCOE compared to Option A, a sensitivity analysis around the total implementation cost was performed. Table 6.10 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

6.6.5.2 Sensitivity Analysis – CAPEX

A sensitivity analysis around the total implementation cost was performed. Table 6.10 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

Table 6.10: CAPEX Sensitivity Analysis

PV System	CAPEX Variance +/-%	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	LCOE ($/kWh)	Utility LCOE ($/kWh)
Option B - 279 kWp DC Bifacial	0%	$1,000,301	$53,229	$57,580	19.6	-$45,214	2.2	$0.3904	$0.2035
	30%	$1,300,391			25.5	-$377,351	-3.5	$0.5153	$0.2035
	-20%	$800,241			15.7	$176,211	7.1	$0.3072	$0.2035

6.6.5.3 Sensitivity analysis – Energy Generation

A sensitivity analysis around the total energy generation was performed. Table 6.11 shows what the simple payback and LCOE range would be if the electricity generation varied between -5% and +5%.

Table 6.11: Sensitivity Around kW/yr Generation

PV System	+/- % kWh/yr	kWh/yr	Total Savings ($/yr)	Simple Payback (yr)	LCOE $/kWh	Utility LCOE ($/kWh)
Option B - 279 kWp DC Bifacial	-	395,465	$50,975	19.6	$0.3904	$0.2035
	-5%	375,692	$48,208	20.7	$0.4110	$0.2035
	5%	415,238	$53,741	18.6	$0.3718	$0.2035

6.7 PV Project Estimated Timeline

The implementation of any of these projects will require the completion of a number of tasks. Considering that an engineering company produces the design and tender package, and a solar PV contractor installs the system (turn-key project), a project timeline was estimated. The tables below depict the estimated timeline to complete the options described for this site.

Table 6.12: Estimated Timeline for Option 1

Task #	Option A and B- Tasks - 308 kWp Monofacial and 279 kWp Bifacial PV Systems	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
1	RFP process to design and create the tender package for the PV system. Select PV designer. If WHRM requires an Engineer to act as Owner's Engineer, an RFP to select it could occur in parallel to the RFP to select the PV designer.	6	6	weeks after RFP was issued
2	PV Designer: Kick-off Meeting, Available Information Review	1	7	weeks after RFP was issued
3	PV Designer: Site Visit	1	8	weeks after RFP was issued
4	PV Designer: PV System Design and Tender Package Preparation	7	15	weeks after RFP was issued
5	WHRM: Design and Tender Package Review	1	16	weeks after RFP was issued
6	PV Designer: Design and Tender Package Update According to WHRM Comments	1	17	weeks after RFP was issued
7	WHRM: Tender Package Is Issued	1	18	weeks after RFP was issued
8	Bidders: Tender Period, Question and Answer Period. Bids are submitted to WHRM.	4	22	weeks after RFP was issued
9	WHRM or Owner's Engineer: Bid Assessment, Question and Answer with bidders, Bids Ranking and Recommendation. Successful bidder is contacted.	3	25	weeks after RFP was issued
10	WHRM: Negotiation with Successful Bidder. Contract signing.	2	27	weeks after RFP was issued
11	PV Contractor: Kick-Off Meeting, Available Information Review, Site Visit.	2	29	weeks after RFP was issued
12	PV Contractor: Equipment Selection and Acquisition. PV System Installation.	14	43	weeks after RFP was issued

Task #	Option A and B- Tasks - 308 kWp Monofacial and 279 kWp Bifacial PV Systems	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
13	WHRM or Owner's Engineer: Design drawings and Shop Drawings Review. Site visits. Communications with PV Contractor (in parallel to above)	14	43	weeks after RFP was issued
14	PV Contractor: System Start-up	1	44	weeks after RFP was issued
15	WHRM or Owner's Engineer: As-built Document and Drawings Review. System Commissioning. Commissioning Report.	4	48	weeks after RFP was issued

7 786 Windsor Back Road – Water Treatment Plant

7.1 Review of Historic Energy Performance

The Windsor Water Treatment Plant located at 786 Windsor Back Road, Windsor, NS, provided electricity bills for a 24 month period spanning January 2022 to December 2023. Energy consumption and demand were reviewed in annual terms to ensure that variation in seasonality was observable. With at least two periods available, a month-to-month comparison of the facility's energy performance was made from one year to the next. Review of electricity consumption profiles based on the information obtained from the two periods was discussed and is compared in this section. This review will also include observed variations in electricity demand by month across the two annual periods.

7.1.1 Electricity Use Profiles

Figure 7.1 provides the monthly electricity usage profile which shows the 24-month period from January 2022 to December 2023.

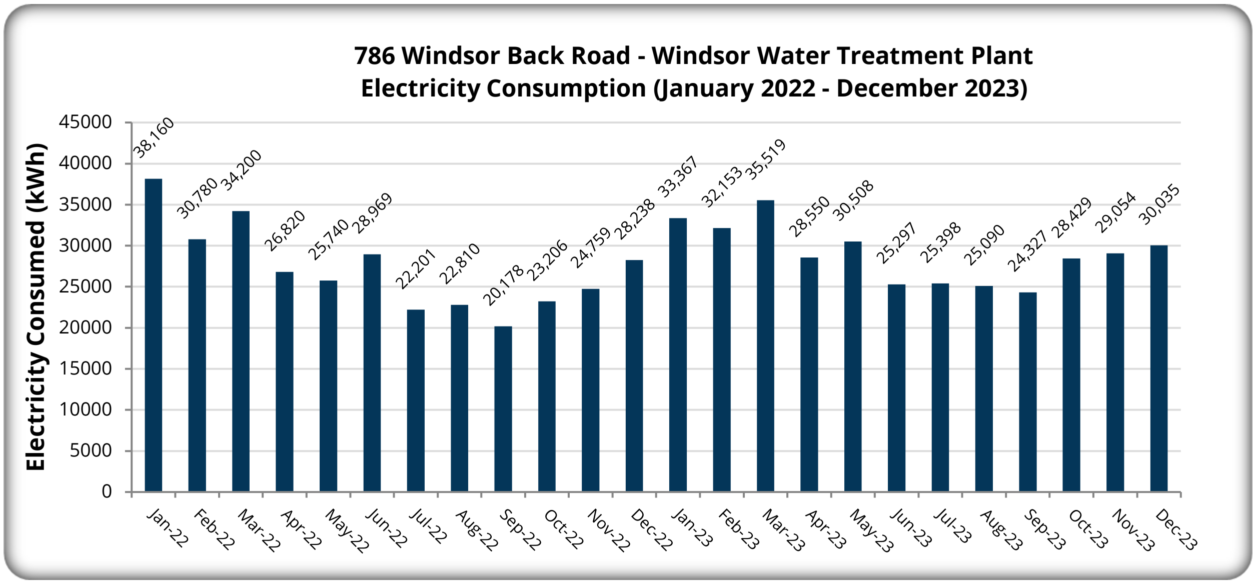

Figure 7.1: 2022/2023 Monthly Electricity Consumption

Figure 7.1 depicts a trend that shows a higher electricity consumption in the winter months, which is most likely due to the demand for space heating in the building. Total electricity usage in the period January 2022/December 2022 was 326,061kWh and 347,727 kWh in the January 2023/December 2023 year. The average annual energy consumption considering these two 12-month periods is 336,894 kWh.

Facility electricity demand was reviewed for each of the months between January 2022 and December 2023. Figure 7.2 presents a monthly peak demand trend for this 24-month period.

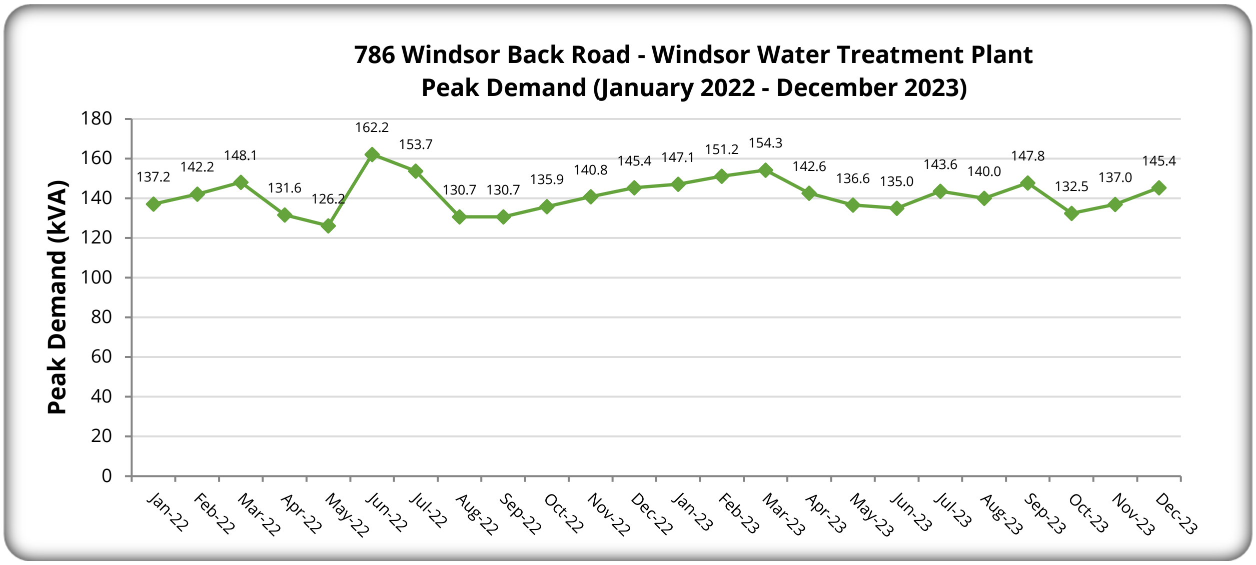

Figure 7.2: Monthly Electricity Peak Demand over 24 Consecutive Months

Figure 7.2 shows a peak demand without a discernible trend, the peak demand at this facility is directly impacted by the amount of effluent that needs to be processed. The monthly peak demand ranges between 126.2 kVA and 162.2 kVA. The highest demand peak was recorded at 162.2 kVA in June 2022 while the lowest demand occurred in the month of May 2022 at only 126.2 kVA.

7.1.2 Electricity Cost

Electricity is provided by the Nova Scotia Power as a “Small Industrial Tariff” electricity rate[48].

[48] Source: [Small Industrial Tariff| Nova Scotia Power (nspower.ca)](). Retrieved: 2024-07-22

SMALL INDUSTRIAL TARIFF

Availability

This tariff is applicable to electric power and energy supplied to any customer, for industrial use, including farming and processing, where the regular billing demand is less than 250 kV.A or 225 kW.

Demand Charge

$8.332 per month per kilovolt ampere of maximum demand

Energy Charge

14.05¢ per kilowatt hour for the first 200 kilowatt hours per month per kilovolt ampere of maximum demand
11.476¢ per kilowatt hour for all additional kilowatt hours

Figure 7.3: NSPI Small Industrial Tariff Rate

The electricity consumption breakdown is depicted in Figure 7.4. This shows that the kWh cost represents about 74.3% and 75.2% of the cost in the monthly power bills in 2022 and 2023, respectively. Monthly electricity cost closely follows the monthly kWh consumption. Total electricity cost in the period January 2022/December 2022 was $50,639 and $56,576 in the January 2023/December 2023 period. The average annual electricity cost considering this two 12-month period is $53,607 . Also, the average unit cost of electricity, considering all costs in the bills, was $0.1591/kWh (not including HST) over the 24-month period provided.

An estimated electricity (kWh only) rate for 2024 of $0.1601/kWh was calculated by applying 2024 NSPI Commercial General Tariff rates to 2023 electricity consumption and peak demand values. A 15% HST was also applied. This average kWh rate does not include the additional demand charge, as the implementation of PV to the facility will not reduce the facility's peak demand.

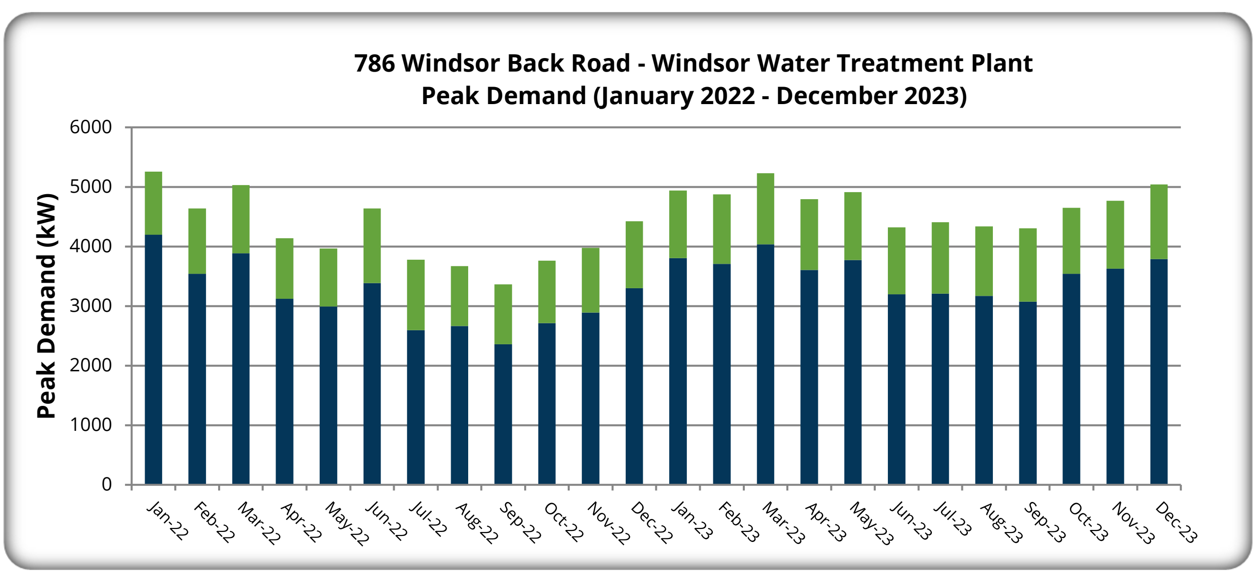

Figure 7.4: Electricity Cost Breakdown

Table 7.1 shows the monthly power bill cost breakdown for the January 2022 to December 2023 24-month period.

Table 7.1: Monthly Power Bill Cost Breakdown for the January 2022 to December 2023

Month-Year	Consumption (kWh)	Consumption Cost ($)	Peak Demand (kVA)	Demand Cost ($)	Invoice Amount ($)
January 2022	38,160	$4,196.04	137.2	$1,058.36	$5,254.40
February 2022	30,780	$3,540.27	142.2	$1,096.93	$4,637.20
March 2022	34,200	$3,886.44	148.1	$1,142.44	$5,028.88
April 2022	26,820	$3,121.47	131.6	$1,015.16	$4,136.63
May 2022	25,740	$2,995.29	126.2	$973.51	$3,968.80
June 2022	28,969	$3,384.45	162.2	$1,251.21	$4,635.66
July 2022	22,201	$2,593.74	153.7	$1,185.64	$3,779.38
August 2022	22,810	$2,664.89	130.7	$1,008.22	$3,673.11
September 2022	20,178	$2,357.40	130.7	$1,008.22	$3,365.62
October 2022	23,206	$2,711.16	135.9	$1,048.33	$3,759.49
November 2022	24,759	$2,892.59	140.8	$1,086.13	$3,978.72
December 2022	28,238	$3,299.05	145.4	$1,121.62	$4,420.67
January 2023	33,367	$3,804.21	147.1	$1,134.73	$4,938.94
February 2023	32,153	$3,710.85	151.2	$1,166.36	$4,877.21
March 2023	35,519	$4,038.66	154.3	$1,190.27	$5,228.93
April 2023	28,550	$3,606.52	142.6	$1,188.14	$4,794.66
May 2023	30,508	$3,772.62	136.6	$1,138.15	$4,910.77
June 2023	25,297	$3,196.28	135	$1,124.82	$4,321.10
July 2023	25,398	$3,209.04	143.6	$1,196.48	$4,405.52
August 2023	25,090	$3,170.12	140	$1,166.48	$4,336.60
September 2023	24,327	$3,073.72	147.8	$1,231.47	$4,305.19
October 2023	28,429	$3,542.36	132.5	$1,103.99	$4,646.35
November 2023	29,054	$3,628.40	137	$1,141.48	$4,769.88
December 2023	30,035	$3,788.34	145.4	$1,252.40	$5,040.74

7.1.3 Total Energy Use Summary

The facility’s total energy usage is shown in Table 7.2. The average for the 24-month period considers the electricity consumption records for January 2022 to December 2023.

Table 7.2: Energy Use Summary

Windsor Water Treatment Plant	2022	2023
Electricity		
Annual Electricity and Demand Cost ($)	$50,639	$56,576
Annual Electricity Consumption (kWh)	326,061	347,727
Annual Electricity Consumption (GJ)	1,173.8	1,251.8
Cost per GJ ($/GJ)	$43.14	$45.20
Percentage of Total Energy (%)	100.00%	100.00%
GHG Emissions (tCO_2/yr)	181.7	156.7
kWh Cost w/o Demand + HST to be used for Cost Savings Estimations ($/kWh)	$0.1601/kWh	

7.2 NSPI Net Metering Program

The Net Metering Program offered by NSPI provides an incentive for on-site renewable power generation. Using a 2-way meter, NSPI records the amount of power consumed by the facility, as well as any surplus power which is generated on-site using renewable technologies and returned to the grid. NSPI then charges the customer for the difference between energy consumed and energy returned to the grid.

NSPI allows the installation of PV systems of a minimum size of 27kW AC up to a maximum 1000kW AC array for net metering if the NSPI customer has a demand meter which this facility does. If the facility is not a winery, farm, or licensed aquaculture plant, the facility could have a PV system with a capacity between 27 and 200 kW AC. If the facility owner has multiple accounts with NSPI, the PV system can supply electricity to other accounts owned by the same person/institution as long as they are within the same geographical area known as NSPI distribution zone.

Annual PV production cannot be higher than the building's annual electricity consumption to qualify for net metering[49].

7.3 Considerations to Size the PV System

The Windsor Water Treatment Plant consumes over 330,000 kWh/yr which makes it a good candidate for a solar PV system with a capacity of about 260 kW (DC). This is the maximum capacity allowed by NSPI for a client that wants to participate in the net metering program. A 260 kW (DC) PV array in Nova Scotia will produce, on average 320,000 kWh (AC) per year, well below the building's annual consumption, thus making the building eligible for the net metering program. The net metering program will permit surplus energy generated from the array to be transferred to the NSPI grid via a bi-directional meter that will record the

[49] Source: Commercial Net Metering| Nova Scotia Power (nspower.ca). Retrieved: 2024-07-31

amount of energy transferred to the grid and credit that amount against future consumption from the grid. This system allows for all energy generated by the array to be used productively without the need or expense of an onsite energy storage system.

7.4 PV System

7.4.1 Ground Mounted

Figure 7.5: Typical Ground Mounted PV Array

The ground mounted PV system can be located on the area west of the building. Water wells and any other infrastructure should be considered when sizing a solar PV array. A typical ground mounted system is shown in Figure 7.5. The implementation of this type of racking system will typically require a geotechnical analysis of the site to be able to design the array foundations. Also, a ballasted PV system can be implemented, which does not require foundations to anchor the racking to the ground. Site conditions are sufficiently typical to permit a standard foundation design for this size of array to be used for this level of analysis. The cost of geotechnical analysis, as part of the detailed system design cost, is included in the capital cost estimate for this array. Alternative mounts such as single or dual axis tracking were not considered due to the additional maintenance requirements.

7.4.2 Roof Mounted

Figure 7.6: Typical Ballasted Roof Mounted PV Array

A PV system can be accommodated on the flat roof with a ballasted racking system. Panels could be placed in landscape position, oriented towards the south at an angle of 10°. Alternatively, a PV system can also be accommodated on a pitched roof, with the panels oriented on a southern roof face at an angle matching the roof slope. This measure should only be considered when the building roof is due for replacement or if it can be determined that the existing roofing system has at least 25 years of remaining life.

HVAC equipment and any other infrastructure should be considered when sizing a solar PV array. A typical roof mounted system is shown in Figure 7.6.

The implementation of a system of this type will require a structural assessment of the roof to determine if it can withstand the load from the PV panels. If the assessment determines that the roof structure cannot withstand the load, then the roof structure will need to be reinforced. The estimated implementation cost includes the cost for the structural assessment, but it does not include the cost for the roof reinforcement (this cost is determined or estimated after the completion of the structural assessment).

7.5 Incentive Programs

7.5.1 Low Carbon Communities Program

West Hants Regional Municipality may be eligible for the *Low Carbon Communities Program.* The program offers funding to recover up to 75% of the total project costs to a maximum of $75,000.The program provides 90% of the funding at the start of the project and the remaining 10% when the project is completed, and the final reports submitted. No more than 75% of the total project cost can be funded through the provincial government[50]. This program requires that reduction in GHG emissions be demonstrated. The expected reductions in capital cost for this project, due to this incentive program, are included in the financial analysis. Further details about the requirements from this program can be found here: Low Carbon Communities - Government of Nova Scotia, Canada. The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

7.5.2 Green Municipal Fund: Local Energy Generation

West Hants Regional Municipality may be eligible for the Green Municipal Fund's *Community Energy Systems: Capital Projects* grant and loan program. The program offers a combined grant and loan up to 80% of eligible project costs to a maximum of $10,000,000. With the grant being eligible for up to 15% of project costs. This program requires the completion of a feasibility study which considers technical and financial, as well as the social and environmental impacts of the project[51]. Further details about the requirements from this program can be found here: Capital project: Community Energy Systems (greenmunicipalfund.ca).

7.5.3 Sustainable Communities Challenge Fund

West Hants Regional Municipality may be eligible for the *Sustainable Communities Challenge Fund: Mitigation Stream*. This fund provides grants up to 80% of eligible projects costs to a maximum of $1,000,000. The applicant must supply a minimum of 20% of eligible project

[50] Source: Low Carbon Communities - Government of Nova Scotia, Canada. Retrieved: 2024-07-31
[51] Source: Capital project: Community Energy Systems (greenmunicipalfund.ca). Retrieved: 2024-07-31

costs, which may be made by alternate funding sources such as federal funding sources. This program requires that reduction in GHG emissions be demonstrated[52]. Further details about the requirements from this program can be found here: Funding Opportunities - Sustainable Communities Challenge Fund (nschallengefund.ca). The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

7.5.4 Low Carbon Economy Challenge

West Hants Regional Municipality may be eligible for the *Low Carbon Economy*. This fund provides grants up to 50% of eligible projects costs for provincial municipalities. The fund ranges from a minimum of $1,000,000 to a maximum of $25,000,000 in available funding. According to the program, the project must produce electricity for the facility's own use. Eligible projects must result in a reduction in GHG emissions. Further details about the requirements from this program can be found here: Low Carbon Economy Challenge Applicant Guide 2023 - Canada.ca.[53] The West Hants Regional Municipality will need to inquire about when applications for this fund will reopen.

7.6 Technical-Financial and Life Cycle Analyses

The sizing and estimation of energy production from the PV system was completed with the modelling software PVSyst, which is one of the most recognized PV modelling software platforms in the world. The PVSyst model considered the building's load profile or energy consumption, the exact location of the PV array, the site's weather data and solar radiation, estimated near and far shading issues, and estimated panel soiling issues.

This analysis included the installed cost of the PV system and, if applicable, financial incentives, and electrical upgrade cost. Additionally, this analysis considered the degradation in power production over time from the PV modules, string inverter replacement cost after ten (10) to twelve (12) years of operation, inflation rate, annual maintenance cost, and discount rate, among other variables. Usually for string inverters, the replacement cost is about 10% of the PV system installed cost.

Four different PV system arrangements were assessed to determine which system shows the better financial performance, such as the lowest levelized cost of electricity and simple payback. The system was evaluated considering standard panels (monofacial) and bi-facial panels. These options include:

1. **Option A:** 178 kWp DC, 160.2 kW AC PV system with monofacial panels. Net metering.
2. **Option B:** 178 kWp DC, 160.2 kW AC PV system with bifacial panels. Net metering.

[52] Source: Funding Opportunities - Sustainable Communities Challenge Fund (nschallengefund.ca). Retrieved: 2024-07-31
[53] Source: Low Carbon Economy Challenge - Canada.ca. Retrieved 2024-07-31

7.6.1 Financial Assumptions

The following list includes all the assumptions and variables considered for the technical and financial analysis of both roof and ground mounted PV systems.

- Solar PV modules capacity: monofacial 555 W; bifacial 550 W
- Inverter: String inverter
- PV panel orientation and angle: due south or slightly southeast at a 40° angle for ground mounted and 10° angle for rooftop array, oriented southwest
- Building annual electricity consumption
- PV system modelled with software PVSyst
- General Inflation rate: 3%
- NSPI Electricity Inflation Rate: 4%
- O&M Inflation Rate: 4%
- Discount rate: 6.5%
- Interest rate: 6.5%
- Life of the project: 25 years
- Equity Ratio: 100% equity if capital <$150,000. If capital is >$150,000, consider $150,000 as equity and the rest as a loan, 20 year loan term if capital >$150,000.
- NS Power GHG emission intensity factor: 0.4506 CO2e kg/kWh in 2023[54]
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr
- String inverter replacement cost in year 12 (10% of CAPEX)

7.6.2 PV Systems Cost

Solar PV contractors in Nova Scotia were contacted to obtain budgetary installed costs for the proposed PV system arrangements, including Supernova Solar, Wattup Solar, and Natural Forces. It was determined that the average installed price for PV arrays with monofacial or standard panels is $2,175-3,000/kWp DC and with bifacial modules is $2,200-$3,075/kWp DC, depending on the system size, racking system, inverter technology (string versus microinverter), and PV installer. These budgetary installed costs do not include HST. This pricing excludes the costs for a geotechnical analysis and any required electrical upgrades and structural modifications to accommodate the new PV system.

7.6.3 Geotechnical Analysis and Cost

Foundation designs of solar photovoltaic (PV) arrays commonly consist of ballasted footings founded at the ground surface (i.e., precast concrete pads), or anchored footings consisting of shallow, driven pile, or helical screw pile foundations embedded below ground. PV arrays also include supporting infrastructure such as service roads, storage shipping containers,

[54] Source: https://www.nspower.ca/cleanandgreen/air-emissions-reporting. Retrieved: 2024-08-09

electrical substations with transformers, concrete pads for electrical equipment, battery storage systems, etc. that each have their own unique foundation requirements.

Geotechnical investigations in support of PV arrays commonly consist of either test pit or borehole drilling investigations. The decision to excavate test pits versus drill boreholes is determined based on site specific requirements and considerations. A desktop study and site visit can help better define the geotechnical field investigation requirements. Underground utility locating should be completed prior to conducting the field investigations.

Geotechnical reports will often be structured in the following way:

- Introduction
- Project and Site Description
- Fieldwork Procedure
- Summarized Subsurface Conditions
- Discussions and Recommendations [including earthworks, foundation design for PVs and associated infrastructure (i.e., bearing capacity and settlement), slope stability, trenching, service roads, construction monitoring, etc.]

In-situ and laboratory testing on soils is conducted to characterize various index, strength, and environmental properties of the soils. This testing may include:

- Standard penetration testing (SPT)
- Moisture content
- Grain size analysis
- Proctor density
- Unconfined compressive strength (UCS) of rock
- Basic chemical testing relating to corrosion of buried concrete and steel including pH, sulphate, and chloride
- Thermal conductivity
- In-situ electrical resistivity
- Other in-situ strength tests as required
- Other environmental quality tests as required

7.6.3.1 Site Description

The site is located at the Windsor Water Treatment Plant, at 786 Windsor Back Road, Windsor, NS. The site contains a water treatment building with an underground 'clearwell' structure as shown in Figure 7.7 and Figure 7.8. It is our understanding that approximately 1 m of fill has been placed overtop of the clearwell. The composition, placement, and compaction of the fill is unknown; however, it is likely that the fill consists of reworked clay till excavated from the area during construction of the clearwell. The west side of the site has been cut into the natural slope. The slope dips eastward toward the treatment building. The geometry of the slope is unknown, but it is assumed that it is at least a minimum of 2H:1V. The PV arrays are proposed to be located on the slope, over the clearwell, and in a cleared area south of the treatment building. Anchored footings are proposed for the slope, and ballasted footings are proposed over the clearwell and in the southern clearing due to buried infrastructure in these areas.

Based on geologic mapping, the principal soil unit in the area is ground moraine and streamlined drift till. The till is described as silty, compact, material derived from both local and distant sources[55].

Figure 7.7: Ortho – 786 Windsor Back Road - Ballasted PV array area (yellow), anchored PV array (blue) (GoogleEarth, 2024)

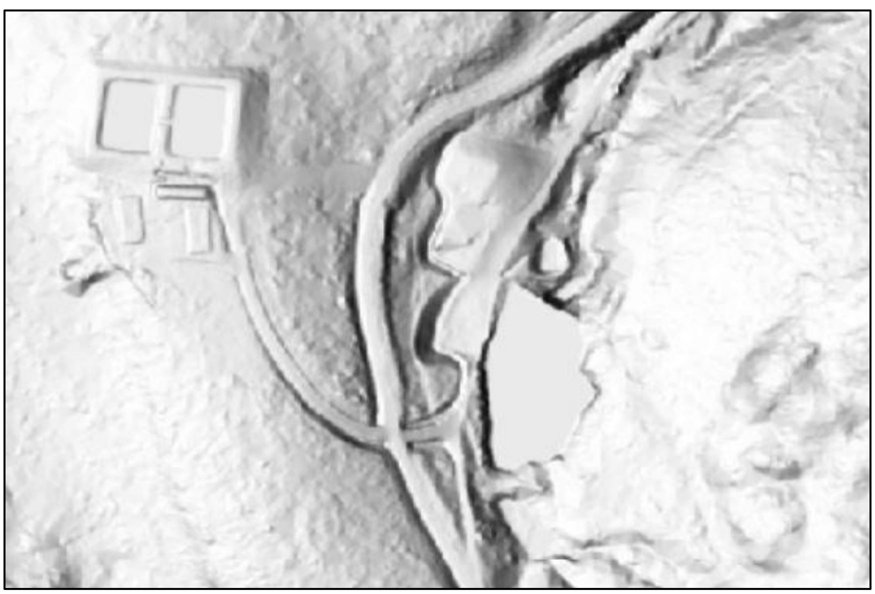

Figure 7.8: LiDAR – 786 Windsor Back Road (GeoNOVA, 2024)

[55] Stea, R.R., Conley, H., Brown, Y. (1992). Surficial Geology of the Province of Nova Scotia – Map 92-3.

7.6.3.2 Potential Geotechnical Challenges

Potential geotechnical challenges include:

- Unknown fill materials at the site.
- Unknown placement and compaction method for fill materials at the site.
- Excavating test pits on slope, over clearwell, and near buried infrastructure.
- Slope stability.
- Bearing capacity.
- Differential settlement fill materials (ballasted foundations).
- Frost heave of fill materials (ballasted foundations).
- Misalignment of ballasted PVs due to settlement or frost heave ballasted foundations).
- Operating construction equipment overtop of clearwell.

7.6.3.3 Suggested Geotechnical Study

To support the PV array foundation design, the following geotechnical study is suggested:

- Geotechnical test pit investigation.
- Approximately 6-8 test pits (2-3 in each proposed PV array area).
- Test pits to be excavated into competent till on slope or south clearing area, or to confirm thickness and consistency of fill overtop of clearwell.
- In-situ and laboratory testing and geotechnical report as described above in General Geotechnical Requirements.

7.6.3.4 Cost Estimate

The cost of the proposed geotechnical investigation would be in the range of $20k - $30k.

7.6.4 Electrical Analysis and Cost

For this site, interconnection with the main MCC is likely the most effective means of connecting the PV system. This location is primarily powered by a three-phase 600V distribution system.

In this option, the PV system size is restricted to the present energy consumption of the site. Therefore, no upgrade to the service entrance is required. A means of interconnecting the inverters with the existing distribution system will be required.

A system at 160kW would export 153A. This is too large to add to the MCC, as it would become overloaded. We recommend installing a splitter and a 175A fused disconnect switch between the load terminal and the MCC. The other lugs on that splitter would be used to interconnect the PV system.

Per NSPI Bulletin B-64-200, a control system will be required to ensure the PV system shuts down upon loss of the utility interconnection.

Table 7.3: Windsor Back Road WTP Estimated Electrical Cost Breakdown

Item	Estimated Cost	Notes
Interconnection Wiring	$3,000	
600A Splitter, NEMA 1	$2,000	
1 x 175kVA Transformer, NEMA 3R	$25,000	Not required if the inverters could be connected at 600A
1 x 400A Disconnect Switch, complete with 400A Fuses	$3,000	
2 x 175A Disconnect Switch, complete with 175A Fuses	$5,000	
ATS Provisions	$1,500	
Total	**$38,000**	

7.6.5 Structural Upgrade Cost

A review of the record drawings, dated 2002, indicated that the roof structure in the area of the proposed PV array is precast concrete tee sections, supported on concrete masonry walls and conventional concrete foundations. The general construction was confirmed during the July 2024 site visit. The drawings also provided design loads for the roof structure including suspended dead load, snow load, and wind uplift. A review of the original design loads, in comparison with the weight of the ballasted PV array, indicates that the overall design load would be increased in the order of 7%, which is higher than acceptable.

The record drawings also indicate that the roof structure is designed for a ballasted roof assembly, a system where the roof membranes are not adhered to the surface but rather held in place by a layer of stone. This type of assembly has a higher dead load than adhered roof assemblies such as modified bitumen roof membranes. On site, it appears that the original ballasted roof is still in place. Considering the age of the roof is likely over 20 years old, it is recommended that the roofing be replaced prior to PV installation. Replacement with an adhered assembly will reduce the dead load of the roof such that with the addition of a PV array system, the stresses on the roof would likely be lower than the structure was originally designed for and strengthening of the roof would not be required.

The National Building Code for Canada (NBCC) 2020, which will be adopted by the Province of Nova Scotia soon, has new design considerations addressing the accumulation of snow drifts around PV systems. The National Building Code for Canada (NBCC) 2020, which will be adopted by the Province of Nova Scotia soon, has new design considerations addressing the accumulation of snow drifts around PV systems. For flat roofs with tilted solar panels, snow drifts will accumulate if the top height of the panels is greater than the base snow depth on the roof. If it is determined that snow drifts will accumulate, this is additional load on the roof and the structure, would need to be reinforced. It is important to note that the design snow load for this building has increased from the code used in the original design of the building to NBCC 2020. If the snow loading distribution on the roof were to change (i.e., the creation of new snow drifts), the entire building would need to be analyzed with loads prescribed by the current code and will potentially require reinforcing. It is recommended that the PV panels be installed in such a way as to avoid the creation of snow drifts and, therefore, most likely avoid any reinforcing requirements. No structural costs would, therefore, be associated with the PV project.

In addition, the treatment facility is undergoing an expansion which is currently in the early stages of design. It is most efficient to plan for rooftop PV installation at this phase of a project, as the roof design loads can be accounted for in the original design, making the associated structural costs of including the expansion in the PV project negligible.

7.6.6 PV System – Net Metering

This PV system was sized considering that all the energy produced has to be consumed onsite and no surplus energy can be exported to the grid. This system would be equipped with a power production control system to monitor the building load to adapt the PV system production and to make sure there is no surplus energy sent back to the grid.

Figure 7.9 shows the 3D models in PVSyst and the area considered for the implementation of the PV system considering monofacial (Option A) and bifacial panels (Option B). The following items were considered when placing the PV system on this part of the property:

- Some shading issues due to the proximity to nearby taller structures/vegetation.
- Relatively flat surface.
- Proximity to the main building, which facilitates their interconnection.
- Excellent exposure to due south.
- Easy access for maintenance.
- Racking system for the PV system will be a combination of ballasted and anchored depending on the infrastructure underneath the PV array and terrain grade.

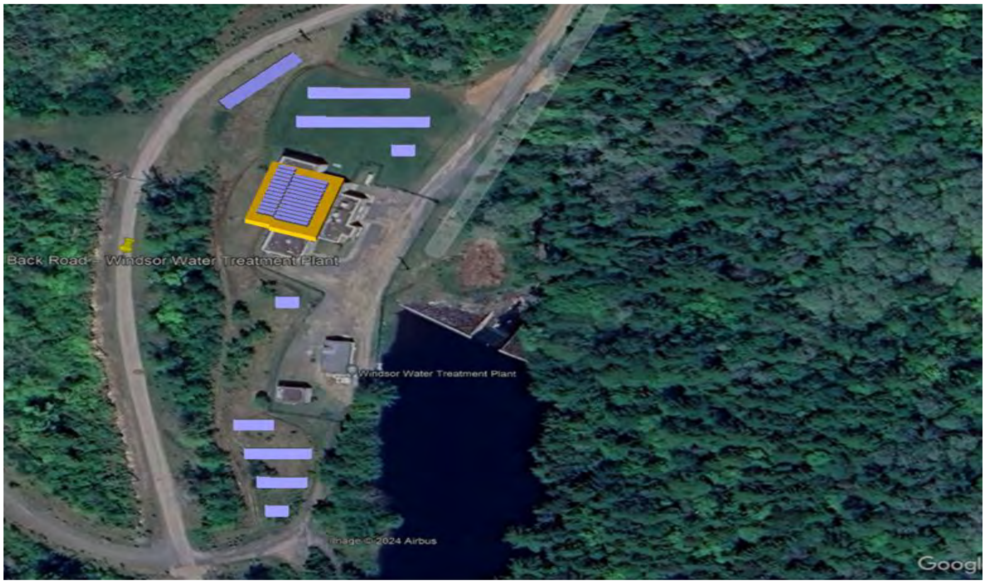

Figure 7.9: Roof and Ground Mounted PV Array – Option A and B

The estimated energy generation from the PVSyst model, as well as the estimated installed cost, current electricity rate, building annual energy consumption, and PV system specific production is included in Figure 7.4. The PVSyst reports are included in Appendix B. Costs in the table below include HST.

Table 7.4: Roof and Ground Mounted PV System – Options A and B

Windsor WTP – Net Metering	Option A – 178 kWp DC Monofacial	Option B – 178 kWp DC Bifacial
Roof Top PV Capacity (kWp DC)	28.7	28.7
Roof Top PV Capacity (kWp AC)	30.0	30.0
Roof Top Installed Cost ($/kWp)	$2,362	$2,362
Roof Top Cost [PV only] ($)	$67,695	$67,695
Ground Mount PV Capacity (kWp DC)	116.0	115.0
Ground Mount PV Capacity (kWp AC)	100.0	100.0
Ground Mount Installed Cost ($/kWp)	$3,228	$3,275
Ground Mount Cost [PV only] ($)	$374,448	$376,625
Total Cost ($)	$442,143	$444,320
Installed Cost ($/kWp)	$3,056	$3,093
Electricity Rate ($/kWh)	$0.1601	$0.1601
Total PV Capacity (kWpDC)	144.7	143.7
Total PV Capacity (kWpAC)	130.0	130.0
Annual Consumption (kWh/yr)	448,051	448,051
Generated by PV and Consumed on Site (kWh/yr)	157,985	196,527
Generated by PV and Exported to Grid (kWh/yr)	28,455	1,324
PV Generation (kWh/yr)	186,440	197,851
PV Specific Production (kWh/yr/kWp)	1,289	1,377

When comparing the results considering monofacial panels (Option A) and bifacial panels (Option B), the following was observed:

- The installed cost per kWp for the ground mounted bifacial panels is approximately 1.4% higher than for monofacial panels.
- All electricity generated by the PV system would be either consumed on site or net metered to the grid.
- Surplus energy is not generated with the considered building energy consumption.
- Option 1A would provide 41.6% of the annual energy consumption.
- Option 1B would provide 44.2% of the annual energy consumption.
- All the energy produced onsite will generate a cost savings at the same rate (NSPI electricity rate).
- The production and specific production from Option B (bifacial) is 5.8% and 6.4% higher than from Option A respectively, even though Option A kWp DC installed capacity is 0.7% larger than Option B.

In addition to these PV costs, other costs should be considered in the financial analysis. Table 7.6 shows the PV installation cost, as well as the electrical upgrade cost, geotechnical analysis, and design cost. As expected, the highest installation cost is for Option B, which also results in the highest total cost.

Table 7.5: PV Cost and Additional Costs - Options A and B

Installed Cost	Option A – 178 kWp DC Monofacial	Option B – 178 kWp DC Bifacial
PV Ground Mounted ($)	$467,820	$474,444
Geotechnical Analysis Cost ($)	$30,000	$30,000
Electrical Upgrade Cost ($)	$38,000	$38,000
Site Fencing ($)	$56,000	$56,000
Design	$25,000	$25,000
Total Project Cost ($)	**$644,820**	**$651,444**

Considering all these costs and the total savings, the following tables show the simple payback, net present value for a 25-year project horizon, life cycle costs (LCC), and the CO_2 emission reductions. Total savings include the energy savings and annual maintenance cost. Maintenance cost includes cleaning the panels twice a year, tightening the mechanical and electrical connections once a year, spot measurements once a year, and remote review of the system performance every three or four months.

Table 7.6: Financial Analysis – Options A and B

Windsor WWTP	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option A – 178 kWp DC Monofacial	$644,820	$31,594	$34,539	20.4	-$146,731	-1.9	75.2
Option B – 178 kWp DC Bifacial	$651,444	$33,199	$36,176	19.6	-$125,050	-1.2	76.9

Option A results in lower installation cost but Option B has a higher total savings, which results in a shorter simple payback period for Option B. The cash flow and LCOE for both projects should be reviewed to further assess these options. The cash flow includes the maintenance cost and the savings from the generated electricity. Typically, a PV system fitted with string inverters requires the replacement of the inverters after ten (10) to twelve (12) years of operation, which results in a high maintenance cost in year 11 or 12.

7.6.6.1 Levelized Cost of Energy (LCOE)

The LCOE measures lifetime costs divided by energy production. It calculates the present value of the total cost of implementing and operating the building over an assumed lifetime. LCOE allows the comparison of different PV projects and different technologies (e.g., wind, solar, natural gas) of unequal life spans, project size, different capital cost, risk, return, and capacities. Figure 7.10 shows the LCOE formula.[56]

The LCOE calculation for this project considered the following variables:

- O&M Inflation rate: 4%
- Discount rate: 6.5%
- Life of the project: 25 years
- PV module production depreciation: 1% in the first year and 0.5%/yr for the subsequent years
- Maintenance cost: 0.5% of CAPEX/yr (the same as in the previous section).
- Inverter replacement cost in year 12 (10% of CAPEX).

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

I_t = Investment expenditures in year t (including financing)
M_t = Operations and maintenance expenditures in year t
F_t = Fuel expenditures in year t
E_t = Electricity generation in year t
r = Discount rate
n = Life of the system

Figure 7.10: LCOE Formula

Table 7.7 shows the costs included in the calculation of the LCOE and the estimated annual energy production factoring power production depreciation. The LCOE for Option A was determined to be $0.5326/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE of the purchase of electricity from the grid is $0.2328/kWh, which is lower than the LCOE for the PV system.

Table 7.7: LCOE Calculation – Option A

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000	-	-	-
1	-	$55,249	-$2,945	215,733
2	-	$55,249	-$3,062	213,576
3	-	$55,249	-$3,185	212,508
4	-	$55,249	-$3,312	211,445
5	-	$55,249	-$3,445	210,388
6	-	$55,249	-$3,582	209,336
7	-	$55,249	-$3,726	208,289
8	-	$55,249	-$3,875	207,248
9	-	$55,249	-$4,030	206,212

[56] Source: https://www.energy.gov/sites/prod/files/2015/08/f2/LCOE.pdf. Retrieved: 2020-02-05

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
10	-	$55,249	-$4,191	205,181
11	-	$55,249	-$4,359	204,155
12	-	$55,249	-$63,423	203,134
13	-	$55,249	-$4,714	202,118
14	-	$55,249	-$4,903	201,108
15	-	$55,249	-$5,099	200,102
16	-	$55,249	-$5,303	199,102
17	-	$55,249	-$5,515	198,106
18	-	$55,249	-$5,736	197,116
19	-	$55,249	-$5,965	196,130
20	-	$55,249	-$6,204	195,149
21	-		-$6,452	194,174
22	-		-$6,710	193,203
23	-		-$6,978	192,237
24	-		-$7,257	191,276
25	-		-$7,548	190,319

The LCOE for Option B was determined to be $0.5134/kWh. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE of the purchase of electricity from the grid is $0.2328/kWh, which is lower than the LCOE for the PV system. The LCOE for the NSPI grid was calculated considering inflation rate and the annual energy consumption of the building.

Table 7.8: LCOE Calculation – Option B

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
0	$150,000	-	-	-
1	-	$55,843	-$2,978	225,960
2	-	$55,843	-$3,097	223,700
3	-	$55,843	-$3,221	222,582
4	-	$55,843	-$3,349	221,469
5	-	$55,843	-$3,483	220,362
6	-	$55,843	-$3,623	219,260
7	-	$55,843	-$3,768	218,164
8	-	$55,843	-$3,918	217,073
9	-	$55,843	-$4,075	215,987
10	-	$55,843	-$4,238	214,907
11	-	$55,843	-$4,408	213,833
12	-	$55,843	-$64,136	212,764

Year	Equity ($)	Loan Payments ($)	Maintenance Cost ($/yr)	PV Production (kWh/yr)
13	-	$55,843	-$4,767	211,700
14	-	$55,843	-$4,958	210,641
15	-	$55,843	-$5,156	209,588
16	-	$55,843	-$5,363	208,540
17	-	$55,843	-$5,577	207,498
18	-	$55,843	-$5,800	206,460
19	-	$55,843	-$6,032	205,428
20	-	$55,843	-$6,273	204,401
21	-		-$6,524	203,379
22	-		-$6,785	202,362
23	-		-$7,057	201,350
24	-		-$7,339	200,343
25	-		-$7,633	199,341

Table 7.9 summarizes the results of the financial assessment for both options. Option B shows the highest NPV and lower LCOE compared to Option A.

Table 7.9: Summary - Financial Analysis - Options A and B

Windsor WWTP	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	LCOE $/kWh	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
Option A – 178 kWp DC Monofacial	$644,820	$31,594	$0.5326	20.4	-$146,731	-1.9	75.2
Option B – 178 kWp DC Bifacial	$651,444	$33,199	$0.5134	19.6	-$125,050	-1.2	76.9

Considering that Option B was shown to have the highest NPV and lower LCOE compared to Option A, a sensitivity analysis around the total implementation cost was performed. Table 7.10 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

7.6.6.2 Sensitivity Analysis – CAPEX

A sensitivity analysis around the total implementation cost of Option B was performed. Table 7.10 shows what the simple payback and LCOE range would be if the total cost varied between -20% and 30%.

Table 7.10: CAPEX Sensitivity Analysis

PV System	CAPEX Variance +/-%	Cost ($)	Total Savings [energy savings - maintenance cost] ($/yr)	Energy Cost Savings ($/yr)	Simple Payback (yr)	NPV ($)	IRR (%)	LCOE $/kWh	Utility LCOE $/kWh)
Option B – 178 kWp DC Bifacial	0%	$651,444	$35,755	$38,752	19.6	-$125,050	-1.17	$0.5134	$0.2328
	30%	$846,877			25.5	-$379,008	-6.9	$0.6810	$0.2328
	-20%	$521,155			15.7	$44,256	3.3	$0.4017	$0.2328

7.6.6.3 Sensitivity Analysis – Energy Generation

A sensitivity analysis around the total energy generation was performed. Table 7.11 shows what the simple payback and LCOE range would be if the electricity generation varied between -5% and +5%.

Table 7.11: Sensitivity Around kW/yr Generation

PV System	+/- % kWh/yr	kWh/yr	Total Savings ($/yr)	Simple Payback (yr)	LCOE $/kWh	Utility LCOE ($/kWh)
Option B – 178 kWp DC Bifacial	-	225,960	$33,199	19.6	$0.5134	$0.2328
	-5%	214,662	$31,390	20.8	$0.5404	$0.2328
	5%	237,258	$35,007	18.6	$0.4890	$0.2328

7.7 PV Project Estimated Timeline

The implementation of any of these projects will require the completion of a number of tasks. Considering that an engineering company produces the design and tender package, and a solar PV contractor installs the system (turn-key project), a project timeline was estimated. The tables below depict the estimated timeline to complete the options described for this site.

Table 7.12: Estimated Timeline for Options A and B

Task #	Option A and B- Tasks – 178 kWp Monofacial and Bifacial System	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
1	RFP process to design and create the tender package for the PV system. Select PV designer. If WHRM requires an Engineer to act as Owner's Engineer, an RFP to select it could occur in parallel to the RFP to select the PV designer.	6	6	weeks after RFP was issued

Task #	Option A and B- Tasks – 178 kWp Monofacial and Bifacial System	Number of Weeks to Complete the Task	Estimated Delivery and/or Completion Date	
2	PV Designer: Kick-Off Meeting, Available Information Review	1	7	weeks after RFP was issued
3	PV Designer: Site Visit	1	8	weeks after RFP was issued
4	PV Designer: PV System Design and Tender Package Preparation	8	16	weeks after RFP was issued
5	WHRM: Design and Tender Package Review	1	17	weeks after RFP was issued
6	PV Designer: Design and Tender Package Update According to WHRM Comments	1	18	weeks after RFP was issued
7	WHRM: Tender Package Is Issued	1	19	weeks after RFP was issued
8	Bidders: Tender Period, Question and Answer Period. Bids are submitted to WHRM.	4	23	weeks after RFP was issued
9	WHRM or Owner's Engineer: Bid Assessment, Question and Answer with bidders, Bids Ranking and Recommendation. Successful bidder is contacted.	3	26	weeks after RFP was issued
10	WHRM: Negotiation with Successful Bidder. Contract signing.	2	28	weeks after RFP was issued
11	PV Contractor: Kick-off Meeting, Available Information Review, Site Visit.	2	30	weeks after RFP was issued
12	PV Contractor: Equipment Selection and Acquisition. PV System Installation.	15	45	weeks after RFP was issued
13	WHRM or Owner's Engineer: Design drawings and Shop Drawings Review. Site visits. Communications with PV Contractor (in parallel to above)	15	45	weeks after RFP was issued
14	PV Contractor: System Start-up	1	46	weeks after RFP was issued
15	WHRM or Owner's Engineer: As-built Document and Drawings Review. System Commissioning. Commissioning Report.	4	50	weeks after RFP was issued

8 Conclusion

The summary of the analysis for each site is shown in Table 8.1, which shows the results from the analysis of the best option (option with bifacial panels) for each site considering the net metering or Community Solar scenario, depending on the site. The highest LCOE was determined to be $0.51340/kWh for the net metering arrangement at the Windsor WTP located at 786 Windsor Back Road. However, the lowest LCOE was determined to be $0.3513/kWh, which was for the community solar arrangement at 1379 Walton Woods Road. The LCOE is not the production cost for the PV system, it is instead a financial indicator that allows the assessment of the technical and financial performance of the solar PV system. The LCOE also allows us to compare “apple to apples” when reviewing different projects.

Table 8.1: Financial Analysis – Summary Results

Site	Option	Cost ($)	Total Savings [energy savings -maintenance cost] ($/yr)	LCOE $/kWh	Simple Payback (yr)	NPV ($)	IRR (%)	CO_2 Emissions Reduction (ton/yr)
1379 Walton Woods Road – Capped 1st Generation Landfill: Community Solar	Option B – 3203 kWp DC Bifacial	$9,442,224	$485,891	$0.3513	19.4	-$4,007,231	-	1987.4
Brooklyn Fire Station 1 and Civic Centre: Net metering	Option 1B - 178 kWp DC	$713,182	$35,919	$0.4297	19.9	-$15,838	1.8	41.9
Brooklyn Fire Station 1 and Civic Centre: Community Solar	Option 2B - 642 kWp DC Bifacial	$1,835,916	$94,194	$0.4125	19.5	-$1,122,548	-	87.2
293 Wentworth Road – Windsor WWTP: Net metering	Option B - 327 kWp DC Bifacial	$1,104,922	$62,765	$0.3799	17.6	$56,350	4.6	106.4
48 Falmouth Connector-Falmouth WWTP: Net metering	Option B – 143.7 kWp DC Bifacial	$548,275	$27,041	$0.4552	20.3	-$73,027	-0.80	88.6
3 Lagoon Drive – Windsor WWTP 'Old Lagoons': Net metering	Option B - 279 kWp DC Bifacial	$1,000,301	$50,975	$0.3904	19.6	-$45,214	2.2	69.9
786 Windsor Back Road - WTP: Net metering	Option B – 178 kWp DC Bifacial	$651,444	$33,199	$0.5134	19.6	-$125,050	-1.2	76.9

Net metered arrangements sites such as: 293 Wentworth Road and the Brooklyn Fire Station, show the highest annual cost savings and show the highest NPVs over the term of the study. Also, the net metering option at 293 Wentworth showed the shortest payback period and the lowest LCOE among the net metering projects. For community solar arrangements, the 1397 Walton Woods Road and the Brooklyn Fire Station have similar simple payback periods.

In summary:

- For ground mounted PV arrays, bifacial panels are the best option.
- The simple payback period, for the majority of projects, ranges from 19-20 years.
- All projects show a LCOE higher than the LCOE calculated for the purchase of electricity from the grid. LCOEs, for certain projects, can be lowered if there is a reduction in any of the following: debt terms, interest rates. or install costs.
- Costs considered in the analysis are preliminary costs provided by PV contractors and service providers. Therefore, it is expected that better (lower) costs should be obtained during a competitive tender process, which will include the technical specification of the systems to allow bidders to offer their best price.
- Costs considered in the projects do not include any potential incentives for which West Hants Regional Municipality may be eligible.
- The community solar options were analyzed considering an assumed PPA rate of $0.12/kWh. Any PPA rate with NSPI must be negotiated and agreed on with NSPI.
- Different sections of the report present sensitivity analyses that consider variations in capital cost, energy production, and PPA rates. These analyses allow the estimation of ranges for payback and LCOEs.
- The timelines estimated for each project are conservative. A shorter implementation time might be achieved, but depends on the equipment availability, contractor expertise and equipment supply chain conditions.
- The net metering project with the shortest payback, lowest LCOE and offers good visibility to the public is at 293 Wentworth. It is worth mentioning that the final PV systems size will depend on the results from the geotechnical assessments.
- The community solar project with the shortest payback, smallest LCOE, and largest GHG reduction impact is at the landfill. However, a full geotechnical study must be completed to determine the best solution for placing the solar systems while keeping the integrity of the capped cells.
- The community solar project at the Brooklyn Fire Station has a higher payback and LCOE compared to the project at the landfill. However, this solar array would be located by a community centre, and therefore, more visible to the public where it could serve as an example for the community.
- The implementation of any of the solar PV options will result in a reduction of GHG emissions purchased from the grid ranging from 41.9 to 1987.4 tonnes per year. The PV arrangement at 293 Wentworth Road shows the smallest simple payback period and the highest carbon saving (tonnes) of the net metering sites at 106.1 tonnes. While 1379 Walton Woods Road shows reduction of 1987.4 tonnes of emissions purchased from the grid.

- If a rooftop PV project is considered for implementation, it is advised to follow the recommendations in this report. PV systems cannot be installed on roofs that are at or near the end of their service life.

IMPORTANT NOTICE:
The opinion of probable costs for this scoping study is presented on the basis of experience, qualifications, and best judgement. It has been prepared in accordance with acceptable principles and practices. Sudden market trends, non-competitive bidding situations, unforeseen labour and material adjustments and the like, are beyond the control of our professional cost estimators. And as such we cannot warrant or guarantee that actual costs and/or savings will not significantly vary from the opinion provided in the preceding sections.

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APPENDIX A

Nova Scotia Community Solar Program Guidelines

Community Solar Program Guide: Updates and Amendments

Updated: May 7, 2024

The following amendments were made to the Community Solar Program Guide published in March, 2024. For questions, contact us by email at sharedsolar@novascotia.ca

Date	Page	Section	Update
April 10, 2024	11		On page 11, in the call out referring to the definition of brownfields and the Canadian Brownfields Network, we strongly recommend reading and implementing the recommendations in the Nova Scotia Brownfield Roadmaps 2021 (fcm.ca) if you intend to site a community solar garden on a brownfield.
April 10, 2024	11-14	**Section 2: NSPI Generation Interconnection Procedures**	**Additional Information re: Transmission Generation Interconnection Procedures** If transmission impacts are identified during the Preliminary Assessment, the applicant will have the option to proceed with the next steps of the feasibility study (as a part of the Standard Generator Interconnection Procedures (SGIP)). This requires paying a $15, 000 deposit to proceed. The feasibility study will provide the applicant with a high level estimate of expected costs and is required as a part of your application to the Community Solar Program. The feasibility study is not as robust as completing the full System Impact Study (SIS), which cannot be completed until after a project receives Community Solar Program approval. *Proceeding with the feasibility study as a part of the SGIP process is at the risk of the project owner, and does not guarantee program approval.* It is likely that most program applicants will proceed with the Distribution Generator Impact Procedures (DGIP) process. The SGIP for transmission interconnection procedures is typically a longer process, and can result in delays in the study queue and result in project delays. If transmission impacts are identified during your Preliminary Assessment, you can work with the System Operator to discuss potential timelines and economic viability of proceeding with the DGIP or SGIP.
April 10, 2024	28	**Section 4: NSPI Generation Interconnection Procedures**	DOCUMENT REQUIRED: Attach a PDF copy of the completed Preliminary Assessment for distribution connected projects *or a copy of the feasibility study for transmission interconnection projects* from NSPI. Refer to NSPI Generation Interconnection Procedures (GIP) for more information.

May 7, 2024	29	**Section 3: Submitting Your Application** section 6 Environmental Considerations and Requirements.	Question 46 of the application form was revised to include a requirement for applicants to provide an overview of their project's decommissioning plan if they decommission their project at any point throughout the project life cycle.

Nova Scotia

Community SOLAR Program Guide

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Disclaimer

This guide is intended to assist the public's understanding of the Community Solar Program. In the event of any discrepancy between this guide and the regulations pertaining to the Nova Scotia Community Solar program, the regulations prevail.

Nova Scotia Community Solar Program Guide
Department of Natural Resources and Renewables
February 2024

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SECTION 1: BACKGROUND

The Province of Nova Scotia is taking a bold new direction to make our province greener and cleaner. Our province has a goal of supplying 80 per cent of electricity from renewable sources by 2030 while reducing greenhouse gas emissions by 53 per cent below the levels that were emitted in 2005.

The new Community Solar Program will help us reach those goals by making it possible for more people to produce and support solar electricity.

The purpose of this guide is to explain the Community Solar Program and provide information to eligible persons or groups who are interested in becoming project owners, and Nova Scotians who wish to subscribe to those projects.

Snapshot of Nova Scotia's Community Solar Program

Nova Scotia's Community Solar Program Goals:

- **Add up to 100 megawatts (MW) of clean, renewable solar generation to the grid, helping to reduce our dependence on fossil fuels and mitigate climate change.**
- **Extend the benefits of solar generation to those unable to access it.**
- **Support local economic development.**

Program Benefits:

- **More Nova Scotians can use solar energy to power their homes.**
- **Subscribers will see a cost saving.**
- **Communities can get involved in developing renewable energy and addressing climate change.**

What Is the Nova Scotia Community Solar Program?

The Nova Scotia Community Solar Program is a way of sharing the benefits of solar energy among multiple participants while supporting local economies and helping the province reach our renewable energy goals.

For an overview, download the What is Nova Scotia's Community Solar Program [PDF].

The program brings together local **project owners** with **solar subscribers**.

Project owners are eligible individuals, businesses, non-profits, and other groups who wish to build, own, and operate a community solar garden to generate clean electricity for participating subscribers.

Project owners can choose to use their solar garden to benefit subscribers from a specific community, group, or geographic area, or they can accept subscribers from the general public.

Want to learn more about becoming a **project owner**?

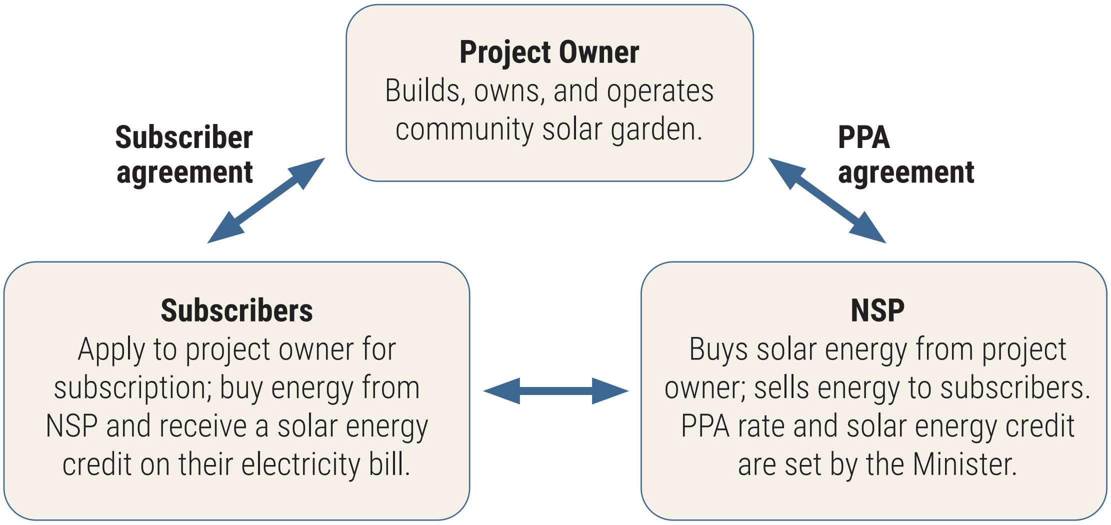
Subscribers are residents and organizations in Nova Scotia who wish to get their electricity from a community solar garden because they

- don't have the right space or conditions to set up their own solar panels
- want to be part of the shift to clean energy
- want to receive a credit for the solar energy that is produced
- want to become a subscriber

How Does the Community Solar Garden Concept Work?

1. Approved project owners build, own, and operate a community solar garden on their land or property. The project owner pays all the costs of the solar garden setup, which includes the equipment, installation, environmental land surveys, and more.
2. The solar garden generates electricity and feeds it into Nova Scotia Power Inc.'s (NSPI) power grid.
3. NSPI pays the project owner a power purchase rate every month.
4. The project owner solicits and registers subscribers to their solar garden.
5. Subscribers get a credit on their power bill for solar energy produced, lowering the total cost of electricity.

Nova Scotia's Community Solar Program



Did You Know?

- **Solar gardens in the Community Solar Program can generate between 0.5 MWac to 10 MWac of energy.**
- **A 1 MWac solar garden covers four to six acres of land and can generate enough energy to power up to 131 individual homes.**
- **All the solar gardens in the program combined will generate up to 100 MWac. That's enough to power over 10,000 homes.**
- **For more information see How much electricity will a community solar garden generate in Nova Scotia? and How does large-scale solar work?**

Who Is Involved in the Program?

The Department of Natural Resources and Renewables is responsible for the creation and administration of the Community Solar Program. All project applications will be submitted to the Minister for approval.

Nova Scotia Power Inc. (NSPI) is responsible for responding to and analyzing requests to interconnect with the grid, electrical permitting and inspections, and contracting for energy with the project applicant. They will also meter all energy and administer the credits to subscribers and assist in subscription management. Project applicants will need to work with NSPI closely throughout the process. For more details see NSPI's Generation Interconnection Procedures.

How Was the Program Developed?

We developed Nova Scotia's Community Solar Program based on significant research across Canada, the United States, and internationally, along with input from stakeholders and knowledge holders here in Nova Scotia.

Community Solar in the United States

Community solar policies and lessons learned in states such as Minnesota and Massachusetts provided insight into program development.

Minnesota was one of the first states to enable community solar and became an early leader as its program flourished since 2013. As of December 2021, Minnesota had 834 MWac of community solar projects installed across 422 projects[1].

Massachusetts' Solar Massachusetts Renewable Target (SMART) program began in 2018. As of December 2021, Massachusetts had 674 MWac of community solar installed across 396 projects[2].

Public Collaboration and Input

The program design was informed by significant input from the public through the following engagement and knowledge sharing:

- Engagement sessions held in 2021 by Clean Foundation and One North End, who were contracted by Natural Resources and Renewables for that purpose
- Best practices and learnings from community solar projects in multiple jurisdictions and geographical areas across Canada and internationally
- An online survey that was sent to a cross section of collaborators in March 2023
- One-on-one consultations with multiple collaborators and contributors that have been ongoing since 2021
- Lessons learned from NSPI's pilot Community Solar Garden project in Amherst, and the three community solar gardens in Berwick, Mahone Bay, and Antigonish, owned by the municipal electric utilities

The result is a program that will help us meet our renewable energy targets, while allowing many more Nova Scotians to support clean energy and save money at the same time.

Existing Community Solar Gardens in Nova Scotia

The first community solar garden in Nova Scotia, a 1.8 MWac solar facility, was built by NSPI in Amherst as a pilot project. The lessons learned from operating this project for the last two years have informed the preparation of the provincial program. The solar garden produces about 2,700 MWh of electricity per year—that's enough to power about 240 homes or 700 battery-powered electric vehicles.

In 2023, the province's municipal electric utilities in the towns of Mahone Bay, Antigonish, and Berwick constructed three community solar gardens, totalling almost 7 MWac.

These examples are outside of the provincial community solar regulations, as per the Electricity Act.

More Information

Links to additional resources, including relevant acts and legislation, can be found on our webpages:

Clean Electricity (Department of Natural Resources and Renewables)

Nova Scotia Community Solar Program

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[1] Data sourced from "Sharing the Sun Community Solar Project Data (December 2021)," The National Renewable Energy Laboratory, U.S. Department of Energy

[2] Data sourced from "Sharing the Sun Community Solar Project Data (December 2021)," The National Renewable Energy Laboratory, U.S. Department of Energy

SECTION 2: INFORMATION FOR PROJECT OWNERS

This section provides valuable insights for organizations interested in participating in the Community Solar Program. Project owners are approved eligible groups, organizations, and even individuals who have the right locations and conditions to build, own, and operate a community solar garden. They play a vital role in advancing clean energy within our province. As a project owner, understanding the program's requirements and guidelines is crucial.

Eligibility Requirements

You can apply to become a project owner if you are one of the following:

- Registered not-for-profit
- For-profit entity
- Mi'kmaw band
- Municipality, town, village, or township
- Co-operative
- Community economic development investment fund (CEDIF) Find more information on CEDIF requirements
- University or college —open to universities across the province as outlined in the University Foundations Act as well as Nova Scotia Community College campuses
- Partnership—may be formed between any of the eligible entities listed above

Project owners must currently be registered and in good standing with the Registry of Joint Stock Companies or be able to indicate and confirm legal status (e.g., a university or First Nations band). Find more information on How to register with Registry of Joint Stock Companies.

Meaningful Partnerships

A meaningful partnership can be defined as "an exceptional level of working together characterized by cohesion, coordination, and collaboration, sustained by co-equal responsibility for the long-term health and success of the partnership." Those involved in the partnership are truly *interdependent* and accountable to one another, to ensure the other feels highly *supported*, and can be successful in the work they do both separately and together.

Meaningful partnerships should be formed in any project development partnership. Meaningful partnerships are expected when a project development partnership is created with a legal entity that represents an underserved or marginalized community in Nova Scotia. Meaningful partnerships can have many agreements surrounding shared collaboration, responsibility and decision making. In most cases, a meaningful partnership will include equal or majority ownership and profit-sharing agreement for the project owner representing a marginalized community.

Project Location and Interconnection

Your community solar garden must be located in Nova Scotia in a territory served by NSPI. Community solar projects are either interconnected to the distribution or the transmission system and do not serve a load or connect behind the meter. However, the costs required to connect to the transmission system will likely exceed the financial viability of the project. All projects are subject to local hosting capacity and Nova Scotia Power Inc's Generation Interconnection Procedures (GIP).

Project Size

Project owners can choose to set up a solar garden with a nameplate capacity between 0.5 MWac and 10 MWac. The size of your project will depend on how much physical space you have available, local hosting capacity near site location, your financial resources, and the number of subscribers you want to service.

You can also learn more in this guide: What Size Should You Make Your Community Solar Garden? [PDF]

The total capacity for all projects in the program is 100 MWac. The program reserves 20 MWac for projects under 5 MWac developed and owned by not-for-profits, co-operatives, and/or legal entities representing underserved or marginalized communities.

What Is a Marginalized Community?

A marginalized community can be defined as a group of people who have historically faced oppression and systemic discrimination based on where they live and interact and/or their culture, language, experiences, or common interests/shared goals. Members of a marginalized group have reduced access to resources, opportunities, and services.

A group of people can be marginalized on the basis of factors such as race, ethnicity, sex, gender, ability, age, religion, socioeconomic status, social class, and geographic location.

Groups generally considered to be marginalized include women, people with disabilities, Indigenous people, members of LGBTQIA2S+ communities, and racialized groups.

See definitions and further information on marginalized, underrepresented, and equity-deserving, -seeking, and -denied groups here.

The Power Purchase Agreement (PPA)

The power purchase agreement (PPA) is a contractual agreement between NSPI and the project owner for the sale of solar energy.

As part of your application, you will calculate and propose a rate called a power purchase rate. The power purchase rate will pay you for the net amount of energy your solar garden generates and sends to the grid. Your proposed power purchase rate must consider all of your sources of funding, financing, and the impact (if any) your proposed rate would have on rate payers. All proposed power purchase rates will be a minimum of $0.07 per kilowatt hour (KWh).

If your project is approved, your awarded power purchase rate will be based on the information you submit in your application. Although you will propose a power purchase rate in your application, the Minister of Natural Resources and Renewables will decide the final rate in the PPA.

The power purchase rate will be your only source of revenue from the solar garden. Your power purchase rate will not change over the course of the agreement (25 years).

Your project may bring in an annual profit, which you are free to use in any way you choose. Some owners may choose to reinvest into additional renewable energy for the community. You could also decide to give profits back to low-income subscribers to subsidize their energy costs.

Renewable Energy Certificates (RECs)

Solar gardens have a unique benefit. They don't produce CO2 like traditional fossil fuel generating facilities, and that means a renewal energy certificate (REC) is issued for every megawatt hour (MWh) of energy generated by the garden. RECs generated by solar projects under this program do not qualify for certification under UL EcoLogo or Green-e Energy Standard. These certification programs require that the renewable energy generated exceed any regulated renewable energy targets. Since the Community Solar Program contributes to Nova Scotia's mandate of 80 per cent of electricity supplied by renewables by 2030, the RECs are ineligible for certification, trade, or sale.

RECs issued under this program will be assigned to NSPI, either as determined by the regulations, or as part of your PPA.

Upon request by a non-residential subscriber, NSPI will register and retire RECs for energy generated by their subscription on their behalf, allowing them to make a verifiable claim of renewable energy usage.

Finding Subscribers

As a project owner, you are responsible for finding and retaining subscribers and managing subscriptions for your solar garden project. At a minimum, your project must have

- at least two subscribers
- 25 per cent of the nameplate capacity subscribed to by residential customers
- at least 85 per cent of the nameplate capacity of the project subscribed to during the term of the PPA, beginning one year after the commercial operation date

The subscribers must be current customers of NSPI in good standing with the utility who are not participating in any other solar programs (such as net metering). You can also be a subscriber of your own project. Other than that, you are free to decide whom you want as subscribers.

Planning Your Community Solar Garden

You will have many topics and issues to consider when planning your solar garden. These range from determining where you will locate it to how you will construct and finance it, as well as understanding how it will affect the environment and nearby communities. This section will guide you through each of these critical aspects.

Planning your project will require consultants and various studies. You may be able to apply for external funding to support preliminary community engagement, readiness and feasibility studies (which may include site selection), as well as preliminary engineering design and geotechnical studies. However, any investment you make using your own money or external funding before receiving approval from the program is undertaken at your own risk. It does not guarantee eligibility for the program or program approval. For more information on potential sources of funding, refer to Financing and Funding for Community Solar Projects [PDF]

Site Selection, Preliminary Engineering, and Geotechnical Studies

Conducting feasibility studies is an important step in determining the best location and design for your project. Choosing a less-than-ideal site could lead to a number of risks, such as unanticipated costs, discovering that the zoning codes won't allow development, or needing additional environmental approvals due to engineering design changes.

Together, site selection, preliminary engineering, and geotechnical studies help minimize these risks and determine if your project is viable by

- analyzing how your system will work
- assessing the available resources at your site and if it is appropriate for a large-scale solar garden
- recommending a system size and design
- providing a resource assessment estimating your project output
- providing an estimate of the cost of the project

We strongly recommend you hire a qualified engineer and/or consultant who has experience working with large-scale solar and is familiar with the unique characteristics of Nova Scotia's geography to conduct your feasibility studies.

Consider the following when choosing your site:

- Your site includes the land you are using, as well as the generating facility, interconnection facilities, and roads.
- The site can be on your own private land, leased land, or, where permitted, provincial Crown land. Learn more about Crown lands and the province's 20 per cent land protection strategy.
- Preference is given to projects located on sites that are less desirable or less likely to be used for any other purpose, such as industrial rooftops, brownfields, and non-arable agricultural lands.
- Smaller projects with different owners can be co-located on the same site. However, if two community-based organizations want to co-locate on the same site, we would prefer they form a partnership for a larger project.
- Project owners must consider ecological, environmental, and archaeological impacts of the project site. Refer to each respective section for more information.
- Access to the local distribution system, including easements for utility equipment.

A brownfield is an abandoned, vacant, derelict, or underutilized commercial or industrial property where past actions have resulted in actual or perceived contamination and where there is an active potential for redevelopment. More information can be found here: Home - Canadian Brownfields Network

NSPI Generation Interconnection Procedures

All projects are required to go through NSPI's Generation Interconnection Procedures (GIP). These are the processes and studies that will tell you if your project is able to connect with the grid at the site you have selected, and if there are any required upgrades. Details on the processes, along with application forms can be found here.

Most community solar projects will require the Distribution Generator Interconnection Procedures (DGIP), applicable to distribution systems 26,400 volts and lower. More information on this process can be found below.

NSPI has created an interactive Hosting Capacity Map. The map provides helpful information on solar hosting capacity for Nova Scotia Power's distribution circuits. Project Owners and their consultant(s) should refer to the solar Hosting Capacity Map prior to starting the GIP to gain a general idea of possible project size at locations across the province.

Pre-application Assessment

Project owners have the option of submitting a Pre-application Assessment. This process applies to generators greater than or equal to 101 kW connected to distribution systems rated 26,400 volts and under. It does not form part of the DGIP, but is designed to provide system information that can help in determining the viability of a generation site prior to a formal DGIP application.

The pre-application assessment is a high-level review of the supply substation, distribution zone, and distribution feeder supplying the proposed generation facility site. It includes system peak and minimum load levels, available distribution zone and feeder hosting capacity, feeder type, number of phases, overhead line data, voltage regulation devices, step down transformation, and a system map showing the interconnection location. It also identifies existing generation and other DGIP interconnection requests in the area that are in the Combined T/D Advanced Stage Interconnection Request Queue.

Distribution Generator Interconnection Procedures

Below is a short summary of the DGIP:

1. **Distribution Generator Interconnection Request**

   Once your site selection study is complete, submit an application for an interconnection request to NSPI using the Distribution Generator Interconnection Request Form. For more information, refer to the Distribution Generator Interconnection Procedures (DGIP) document.

2. **Interconnection Preliminary Assessment**

   If your application is deemed valid, you will be assigned an initial queue position. NSPI will proceed with completing a preliminary assessment which will identify any potential adverse system impacts that would result from the interconnection of the generating facility. It will not determine the maximum capacity of generating facility that can be installed at the specified point of interconnection.

You will receive an order-of-magnitude cost estimate of any required system additions and upgrades to accommodate the generator, and any other useful information to help your project's engineer make a recommendation. It will also demonstrate if there are any transmission impacts expected.

The preliminary assessment goes along with your site selection study. Together, these two reports will provide you with preliminary information on the feasibility of your project, including the distribution level capacity that is available at the location you are considering.

Note that this initial assessment by NSPI is not a guarantee you will receive the indicated available capacity at the proposed location for the proposed project.

NSPI will contact you once the assessment is complete. Based on the information you receive, you may decide to continue with your application to the Community Solar Program for this site, or you may decide to consider another site or other avenues to participate in renewable energy programs.

If you receive Community Solar Program approval and decide to continue with your project, you will need to meet the progression milestones in order to advance in the DGIP process. Details are available in the previous link to the Distribution Generator Interconnection Procedures document.

3. **Distribution System Impact Study (DSIS)**

To be eligible for inclusion in the DSIS stage and advance the initial queue position of the interconnection request, progression milestones described under section 7.2 of the DGIP must be met by the interconnection customer at least 10 business days prior to the DSIS period commencement date. The DSIS process can take +/-12 months, and you must plan for this in your project timeline and construction plan.

A DSIS shall consist of a short circuit analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. NSPI completes the DSIS based on the information provided with the interconnection request, and develops specific interconnection requirements and cost estimates for any required system additions/upgrades. The DSIS is then provided to the interconnection customer (project owner) for review.

The DSIS will identify the scope and responsibilities of the interconnection customer and NSPI for procurement and installation. Based on the DSIS findings, NSPI and the interconnection customer develop the project specific terms of the Standard Small Generator Interconnection Agreement (SSGIA).

DGIP summary table

Class 2: Generation ≥ 101 kw[9]	1) Interconnection Request 2) Preliminary Assessment 3) Distribution System Impact Study 4) Standard Small Generator Interconnection Agreement	$750 per interconnection request	$10,000 refundable deposit. Applicants are invoiced for actual costs with the deposit applied or refunded to the balance as applicable. Optional additional study deposit of $7,500 at request of IC.	1) NSPI will acknowledge receipt of the Interconnection Request within 5 business days. 2) NSPI will attempt to complete the Preliminary Assessment within 30 days. 3) NSPI will attempt to complete the DSIS within 90 calendar days.	NSPI will group studies (cluster) within zones. NSPI can fast-track projects that the preliminary assessment shows will not have material impact on the distribution system.

Construction Plan

As a project owner, you will develop a construction plan that details the activities involved in the construction phase of your community solar garden project.

These activities include

- site preparation
- mounting and array support installation
- solar array installation
- installation inspections and plans review
- risk management, quality assurance, and control
- commissioning

Please refer to the Construction Plan template to learn about projected timelines of constructing a community solar garden. You will be asked to complete and submit the construction plan for your project using the template provided.

Environmental Considerations and Requirements

Nova Scotia Department of Environment and Climate Change does not regulate or approve large-scale solar developments. However, as a project owner, you will need to consider the environmental impacts your project could have and follow relevant legislation and regulations outlined in the Environment Act, and any other standards and guidelines for project activities that take place during construction, operation, and decommissioning.

Impacts to consider include the following:

- Disturbance/land use impacts
- Potential impacts to specially designated areas
- Location of project site in relation to parks and protected areas
- Impacts to soil, water, and air resources
- Impacts to vegetation, wildlife and wildlife habitat, and species at risk
- Impacts to migratory birds due to tree clearing
- Visual, cultural, paleontological impacts
- Socioeconomic and environmental justice impacts
- Potential impacts from hazardous materials
- Regional ecological connectivity

Regional ecological connectivity refers to lands that, due to their location on the landscape and their ecological condition, play a critical role in biodiversity conservation by facilitating the flow of ecological processes and native species (terrestrial species, birds, bats, aquatic species, etc.) across the landscape, including between relatively intact natural areas and between protected areas. As part of your planning, you should evaluate how your project will impact the regional ecological connectivity.

If you are clearing trees between May 1 and August 15, you should have the area assessed by a professional before clearing starts. Information on nesting periods can be found here: Nesting periods - Canada.ca.

Visit these sites for more information:

- Role in Solar Farm Developments (Department of Environment and Climate Change)
- Wetland_Identification_Checklist.pdf (novascotia.ca)
- Wetlands | Wetlands (novascotia.ca)
- Nova Scotia Parks and Protected Areas System (arcgis.com)

Permits and Approvals

Project owners are responsible to be aware of and acquire the relevant permits, licences, authorizations, and approvals needed for their community solar project. The requirements outlined in this document are based in legislation, regulations, policies, and guidelines as well as government priorities and strategic directions. These are amended from time to time, and you are strongly encouraged to confirm requirements with respective offices and departments.

This section provides information about common permits and approvals required for community solar projects. For more information, please refer to the Provincial and Federal Permits and Approvals Resource, and websites of respective offices and agencies for more information.

Land ownership and right of access: You are required to state whether you own the project location or whether you rent, lease, or require access to provincial, federal, or reserve land. If you require the use of any land you do not own, including accessing the land between your project and the NSPI distribution site, you must provide evidence that you have permission to access the land, including the necessary leases, permits, licences, etc. If you intend to site your project on Crown land, you must acquire necessary permits and provide the proof of purchase or access with your Community Solar Project application. For more information, visit Applications to Use Crown Land, Sell or Donate Land to the Province | novascotia.ca.

Indicate if the land has been leased for the lifetime of the project, or if the municipality has secured an option on the land.

Land use and other requirements from municipalities and local authorities: You must demonstrate knowledge and understanding of the municipal by-laws that apply to your project and a commitment to comply with them. These could include land use by-laws, public engagement requirements, environmental effects, road access and traffic management, municipal services connections (water, fire hydrants etc.), landscaping, emergency management procedures, easements or restrictive covenants, rehabilitation of any temporary disturbance, building code permits, and licences. Contact local authorities where your project is located for more information and to obtain information and permits.

Did you know?

As an interconnection customer, you have to provide NSPI with proof of land ownership or access, such as licenses, rights of way, or easements, that are needed to allow the distribution provider to build, operate, maintain, repair, test, inspect, replace or remove facilities and equipment related to interconnection processes.

Work permit for roads and trail construction, including water crossings: You must consult with the Nova Scotia Department of Public Works to ensure that surrounding infrastructure (roads, bridges, etc.) is able to support the weight and size of the technology when in transport. Further discussions between project owners and Public Works may be necessary if a project is located near highways, railways, or other significant infrastructure. For more information, visit Permits, Approvals and Licences|novascotia.ca.

Archaeology permits/consideration of archaeological and heritage resources: The Department of Communities, Culture and Heritage offers an environmental screening process that examines archaeological, paleontological, flora and fauna resources in the area, as well as cemeteries and shipwrecks (where appropriate). This process will identify whether cultural and/or heritage resources may be impacted by your renewable electricity project. If you are unsure whether the screening process is necessary, you can forward project plans to the Department of Communities, Culture, and Heritage and receive advice on whether a screening is recommended. If an environmental screening is completed for your project, you will need to provide a summary of the screening assessment, including any identified issues and how you will mitigate them.

An archaeological resource impact assessment and heritage research permit may be required for projects that have the potential to impact archaeological resources in Nova Scotia. If your project requires a resource impact assessment or heritage research permit due to archaeological or heritage resources that may be affected by your project, you will need to provide a summary of any impacts on your project, including cost and timing implications in your application.

If your project has the potential to impact Mi'kmaw cultural resources, archaeologists are strongly encouraged to engage the Mi'kmaw as part of project planning and implementation. To apply for a permit and to review the guidelines for the applicable permit, visit Archaeology Permits and Guidelines | Communities, Culture, Tourism and Heritage (novascotia.ca).

You will be asked to list all permits and approvals obtained or applied for as part of your application.

Financial and Business Planning

The economic viability of your proposed project plays a key role in your application approval. Ensure your project is well-planned and financially sound before you apply.

You will be asked to provide the following in your application:

- A completed financial template outlining
  - projected capital costs of the project, including interconnection costs
  - the amount of, and information on, funding, grants, and tax credits you anticipate receiving, in addition to information about your financial institution and expected borrowing rate
  - your proposed power purchase rate, in $ per kilowatt hour
  - copies of quotes and other documentation confirming your financial projections and proposed PPA rate
- Approval from the Minister of the Department of Municipal Affairs and Housing to borrow from the Municpal Finance Corporation (municipalities only).

Financing, Sponsorships, and Grants

Planning for your project will require consultants and various studies. We recognize that preparing these pre-project studies may require a financial investment on your part; however, making that investment does not guarantee your project will be approved for the program.

You may be able to apply for and receive external funding for preliminary feasibility studies such as site selection, preliminary engineering and design, geotechnical studies, and community engagement. You may also be able to apply for grants and funding to help with capital costs related to building your project.

Any investment you make of your own money or external funding prior to receiving approval from the program is done at your own risk and does not guarantee eligibility for the program or program approval. See Financing and Funding for Community Solar Projects for more information about potential sources of funding for community solar.

Community Engagement and Support

Having community and public support is important to the success of your project. Find out well in advance if the members of your community support the development of your solar garden. Community engagement can provide vital local knowledge, reduce the risk of challenges and delays, and identify how a project can bring value to a community.

The Community Solar Program application will require you to demonstrate that you have engaged with any Mi'kmaw communities impacted by your project (see more below), and that the public has been consulted.

Your engagement efforts can take many forms, including in-person meetings, video meetings, websites, and more. Make sure you consider accessibility when designing your sessions so persons with disabilities are able to attend, fully participate, and respond. The Canadian Renewable Energy Association's Best Practices for Indigenous and Public Engagement provides helpful guidelines to assist project owners with public engagement.

Nova Scotia has knowledgeable organizations that can help facilitate community engagement. The Conseil de développement économique de la Nouvelle-Écosse (CDENE) can provide assistance and guidance for engaging Acadian communities surrounding your project site. Visit the African Nova Scotian Road to Economic Prosperity to connect with individuals who can provide guidance with engaging African Nova Scotian communities.

Your application requires evidence of community engagement and support which includes

- a summary, including dates, locations, and formats, of the engagement sessions you held
- a municipal council resolution, or letters and other written evidence
- proof that you responded to any community concerns (if applicable)
- documentation demonstrating consultations with Mi'kmaq First Nations in the area the project is to be located, such as letters of support from Chief and Council and other community organizations and members
- details of additional equity-deserving populations in the area, such as African Nova Scotian and Acadian communities and evidence of engagement with those communities

Engagement with the Mi'kmaq

Proponents must demonstrate engagement with the Chiefs and councils of the Mi'kmaq of Nova Scotia communities in proximity to the project site. This may include more than one community.

When engaging with the Mi'kmaq of Nova Scotia, we strongly recommend using the approach described in Proponents Guide: The Role of Proponents in Crown Consultation With The Mi'kmaq of Nova Scotia. Hiring a qualified engagement consultant with recent and specific experience consulting and collaborating with Mi'kmaw communities in Nova Scotia is recommended.

You may include details on progress for completing a Mi'kmaq Ecological Knowledge Study (MEKS) in your application for additional consideration during evaluation. A MEKS must be conducted in accordance with the Mi'kmaq Ecological Knowledge Study Protocol.

Community Benefits

Your application will ask you to describe how your project will benefit your prioritized subscriber community, or the province in general.

These benefits include the following:

- Capacity building—how your project will strengthen future renewable energy in the community, including increasing knowledge and skills in the community.
- Benefit agreements—how you will engage subscribers from and direct a portion of your project revenues back to, a particular community, such as low income or equity deserving communities.
- Economic benefits—how your project will create local jobs, benefit local manufacturers, corporations, venders, contractors, consultants, and service companies.

- An equity, diversity, and inclusion (EDI) plan—how your project will improve the gender balance and increase the diversity within your corporate or organizational structure as well as your broader hiring and supply chains.

Your application will require you to describe how the project will enable equitable access to renewable energy by underserved and marginalized communities.

Subscription Model

Project owners are responsible for

- recruiting subscribers during the term of the PPA
- ensuring NSPI and each subscriber receives a completed subscription agreement
- ensuring that at least 85 per cent of the nameplate capacity of their project is subscribed to during the term of the PPA beginning one year after the commercial operation date

Project owners may choose to delegate subscription management to a third party.

In the application form, you'll need to give a brief overview of the following:

- Your intended subscriber community
- How many subscriptions you plan to make available
- The expected mix of subscriber types (residential, commercial, and industrial)
- The average subscription size in kilowatts (kW)
- Your strategy for engaging subscribers

Prioritized Subscribers

Project owners may choose to prioritize offering subscriptions to a specific group of people or community. Community is defined by those who belong to the community. In some cases, geographic boundaries may apply; in others, it may apply to anyone who feels they are a part of the community defined by the project owner.

For example:

- First Nation or African Nova Scotian community project owners may choose to prioritize offering subscriptions only to people who live in their community or are a member living elsewhere in the province.
- not-for-profits that own affordable living accommodations across the province may choose to prioritize offering subscriptions only to residents of those accommodations.
- co-operatives owned by members of the LGBTQIA2S+ community may choose to prioritize offering subscriptions only to other members of their community.

You can also be general and solicit subscribers from anywhere—subscribers do not have to live near your solar garden.

Determining the Number of Subscriptions

The number of subscriptions your community solar garden can have will be based on the nameplate capacity of your solar garden, how much energy it is expected to produce in one year, and the annual energy usage of your potential subscribers.

See How much electricity will a community solar garden generate in Nova Scotia for additional information on what affects the amount of electricity solar gardens produce.

The following example gives a simplistic view of how much electricity your solar garden could potentially produce in Nova Scotia.

First, start with your project's nameplate capacity. This is the maximum amount of power the solar garden can generate at any moment. In this example, it is 1,000 kWac.

If Nova Scotia had sunshine 24 hours a day for 365 days a year, there would be 8,760 possible hours of sunlight in one year.

As the sun doesn't shine all day, every day, we need to account for the time the garden is producing energy. A project capacity factor (CFac) is used to account for the amount of time each year that the solar garden generates energy. In Nova Scotia, a capacity factor for large solar is estimated to be anywhere between 12 and 18 per cent.

Step 1:
8,760 hours per year x 18% CFac per year = 1,576 hours of expected solar generation each year.

Step 2:
Multiply the number of hours in Step 1 by the nameplate capacity of your solar garden.

1,576 hours x 1,000 kWac = 1,576,000 kWh per year.

This is the amount of energy our example solar garden could generate annually.

Step 3:
Divide the number of kWh we expect the solar garden to generate by the average household electricity use in Nova Scotia (12,000 kWh).

1,576,000 kWh / 12,000 kWh = 131

We see that a 1,000 kWac community solar garden in Nova Scotia could power 131 households each year. So, this garden could potentially support 131 residential subscribers.

The amount of energy your solar garden actually produces depends on many factors and can only be estimated by a qualified engineer or consultant. The actual number of subscribers your solar garden can have depends on how much the solar garden produces and the size of each subscription.

Calculating Solar Credits for Subscribers

Subscribers choose how much of their electricity usage they want to offset with solar. This can range from 10 per cent to 100 per cent.

Each month, they will receive a monthly credit of $0.02/kWh based on the actual amount of energy your solar garden generates and in proportion to their subscription size as a percentage of the solar garden's nameplate capacity.

You do not pay them this credit; NSPI applies it to their bill.

The credit amount is the same for every subscriber, regardless of rate class, and does not change throughout the life of the PPA (25 years).

For example:

If an average monthly bill is $200, with 100 per cent solar offset, the subscription would be 8kW.

A subscription this size is estimated to generate 12,000 kWh.

The annual solar energy credit would $240 (12,000 kWh X $0.02 cents per kWh), or an average of $20 per month.

The solar energy credit is based on the actual energy generated by the solar garden, so it will vary each month based on the season and the weather.

Risk Assessment

A risk assessment is a process of identifying, analyzing, and evaluating potential risks that could affect the success of a project. In the case of a large-scale solar project, the risks could be related to such things as technical, environmental, or economic factors associated with the development and operation of your solar garden.

Your application will require you to complete a Risk Assessment Template, where you will

- identify potential risks
- assess the likelihood and severity of each risk
- develop mitigation strategies

SECTION 3: SUBMITTING YOUR APPLICATION

Before you start your application, answer these questions:

- Are you a member of one of the **eligible groups**?
- Are you submitting one application per project, per site?
- Is your project site physically located in Nova Scotia?
- Will your project be in the service territory of NSPI and able to be connected to NSPI's electrical system?

If you answer no to any one of these questions, you are not eligible for the Community Solar Program.

Submitting an Application

Go to the Community Solar webpage and download the application form and required templates. You can submit the application form and associated documents by email to sharedsolar@novascotia.ca.

In the event that an application is incomplete or additional information is required, you will be notified within 45 business days after the application is received. You then have 45 business days from the date of the request to supply the requested information to the Department of Natural Resources and Renewables.

Once a completed application has been submitted, you will not be able to change the information provided. Be sure to carefully review the information provided for accuracy.

Application Outline

The Community Solar Program application contains the following sections:

Section 1: Applicant Information

Section 2: Project Partnership

Section 3: Project Information

Section 4: NSPI Generation Interconnection Procedures (GIP)

Section 5: Construction Plan

Section 6: Environmental Considerations and Requirements

Section 7: Permits and Approvals

Section 8: Financial Planning

Section 9: Community Engagement and Support

Section 10: Community Benefits

Section 11: Subscription Model

Section 12: Risk Assessment

Section 13: Final Checklist

Section 14: Affirming Statement

Section 1: Applicant Information

- **Applicant's Legal Name:** The applicant's name is the legal name of the qualifying organization.
- **Business Name:** The business name is the registered name under which the primary applicant is operating or doing business (if different from above).
- **Primary Applicant Eligibility:** Only one group may be selected at this time. Select one of the eligible groups that describes the primary applicant with the largest ownership in the project. Partnership information will be asked later in the application form.
- **Represented Community:** If the primary applicant represents a **marginalized community**, provide a description of the community represented.
- **Registry of Joint Stock Companies Number:** Provide a seven-digit Registry of Joint Stock Companies ID number issued to the primary applicant. If not registered with the Registry of Joint Stock Companies, you will be asked to attach a proof of legal status of your organization.
- **Organization's Primary Legal Civic Address:** Provide the legal civic address of your organization. and mailing address of organization. Provide the mailing address if different from the legal address.
- **Organization's Primary Contact (Designated Representative):** Your primary contact is your designated representative who will receive communications regarding your application from the department.
- **Organization's Secondary Contact:** Your secondary contact is an individual the organization can contact in case they cannot reach the designated representative.

Section 2: Project Partnership

Complete this section if the project is owned by a partnership of two or more legal entities, or by a corporation created by a partnership between two or more legal entities.

Provide the following information for each partner organization or entity:

- **Partner's Legal Name**
- **Partner's Business Name:** If different from legal name.
- **Partner's Registry of Joint Stock Companies Number:** Provide a seven-digit Registry of Joint Stock Companies ID number issued to the partner organization. If not registered with the Registry of Joint Stock Companies, you will be asked to attach a proof of legal status of your organization.
- **Partner Organization's Eligibility:** Select one of the eligible groups that describes the partner organization.
- **Represented Community:** If the partner represents a marginalized community, provide a description of the community represented.
- **Partnership Structure:** If your project is based on a partnership, describe how ownership is divided, including the percentage of ownership for each legal entity, voting power, and the profit-sharing agreements.

  DOCUMENTS REQUIRED: Provide documentation supporting partnership agreements, memorandum of understanding, or contracts demonstrating compliance with the partnership /ownership structure you have selected as part of your application.

- **Project Owners with Multiple Program Applications:** If any applicants are project owners or partners on more than one application to the Community Solar Program, you will be asked to describe the project and the percentage ownership of each partner on the other application(s).

Section 3: Project Information

Project Proposal

- **Project title:** Provide the title for your project.
- **Project Summary:** Provide a summary of your project, including why the project is needed, its goals, expected results, and your proposed group or community(ies) you intend to benefit from the project.

Project Size

- **Nameplate Capacity:** Provide your project's nameplate capacity in MWdc and MWac.
- **Net Annual Projected Output in MWhac and kWhac:** Your engineer will provide this information in your site selection/resource assessment.

  DOCUMENT REQUIRED: Provide a copy of the resource assessment from your consultant/engineering firm showing the projected net annual specific output, in MWhac and kWhac. The net annual specific output is the projected number of MWh/kWh ac that is expected to be delivered by the project to the grid.

- **Projected Capacity Factor:** A project's capacity factor is a percentage showing the specific output of your project in relation to the installed nameplate capacity. Your engineer can provide you with this information. For more information on capacity factor see How much electricity will a community solar garden generate in Nova Scotia?

Project Site and Design

Note: You can submit one application per project, per site. You cannot set up multiple small gardens on one site and apply for each as a separate project.

- **Site Location:** If the location of your project is not the same as the address provided in the applicant information section above, provide the address here.
- **Geographic Coordinates or Property Identification Number:** Provide either the geographic coordinates of your project site location or the Property Identification Number(s) (PID). The project site includes the land you are using, as well as the generating facility, interconnection facilities, and roads

  DOCUMENT REQUIRED: Provide a GIS photo of your project site.

- **Project Land Area:** Provide a description of the land, including if it is a brownfield or agricultural land, and if so, provide the land classification. Provide the size of the land area, in acres, that will be used for your community solar project.
- **Scaled Site Plan Map**

DOCUMENT REQUIRED: Attach a PDF scaled site plan map showing the project's relation to each of the following:

- local communities
- structures and occupied buildings
- transportation facilities
- proposed routes of access
- parks and protected areas
- wetlands and watercourses

- **Summary of feasibility studies:** Provide a summary of findings of your site selection, preliminary engineering and design, and geotechnical studies.

  DOCUMENT REQUIRED: Summary of feasibility studies

Note: You do not need to include copies of the study results with your application; however, a project audit may require you to provide proof of the summary provided in the application. If you are unable to produce the study, or the study does not confirm the suitability of your site, your PPA may be revoked or reduced.

See the **Site Selection, Preliminary Engineering, and Geotechnical Studies** section for more information.

Section 4: NSPI Generation Interconnection Procedures (GIP)

- **Point of Interconnection:** Provide information on the interconnection zone of your project

  DOCUMENT REQUIRED: Attach a PDF copy of the completed preliminary interconnection assessment from NSPI. Refer to **NSPI Generation Interconnection Procedures (GIP)** for more information.

Section 5: Construction Plan

- **Planned Project Start Date** for your project.
- **Planned Project End Date** for your project.
- **Community Solar Garden Operation Date**.
- **Construction Plan**

  DOCUMENT REQUIRED: Complete the Construction Plan Template, providing your timeline for the construction phase of your project and submit it along with your application form.

- **Contractors and Developers:** Provide information about contractors you will work with throughout your project cycle.

Section 6: Environmental Considerations and Requirements

It is your responsibility as a potential project owner to be aware of, apply for, obtain, and demonstrate compliance with any applicable regulatory requirements for your community solar project.

You do not need to submit environmental studies conducted for your project. However, upon request by the Department of Natural Resources and Renewables, such studies must be made available.

Refer to Environmental Considerations and Requirements in section 1, as well as the Provincial and Federal Permits and Approvals Resource for help completing this section. ***Note:*** *The resource is provided only as a guide. It is the applicant's responsibility to meet all the regulatory requirements for your project.*

Section 7: Permits and Approvals

Using the space in the application form, identify all permits and approvals you obtained or will obtain for your community solar project.

Refer to Permits and Approvals in section 1, as well as the Provincial and Federal Permits and Approvals Resource for help completing this section. ***Note:*** *The resource is provided only as a guide. It is the applicant's responsibility to meet all the regulatory requirements for your project.*

Section 8: Financial Planning

In this section you will provide details of your project costs and proposed power purchase rate, and the financial goals of your project.

Documents Required: Complete the Financial Planning Template, and submit it along with your application form. Include copies of quotes you have received, and any other information supporting your proposed PPA rate, such as pro forma financial documents from your accountant.

Review the **Financial and Business Planning** section for more information.

Section 9: Community Engagement and Support

Provide details of planned and completed engagement activities with the public. This includes engagement with the Mi'kmaq, African Nova Scotian and Acadian communities, and other marginalized or equity-deserving groups and communities. Refer to the sections on **Community Engagement and Support and Engagement with the Mi'kmaq** for additional guidance.

DOCUMENTS REQUIRED: Provide copies of documents and reports that demonstrate community engagement and support for your project with your application.

Section 10: Community Benefits Plan

Describe how your project will deliver benefits to a specific or broad community. For more information about each community benefit category, review the **Community Benefits section**.

Section 11: Subscription Model

Respond to each question, providing the following information:

- **Your subscribers:** Indicate your targeted or prioritize subscribers group(s) by providing information such as geographic boundary(ies) or community descriptions.
- **Indicate if any of the subscriber groups** identified in the previous question represent an underserved or marginalized community or population in Nova Scotia.
- **Your "warm list":** Identify if you have completed a list of potential subscribers from the community. A warm list should represent at least 10 per cent of the nameplate capacity of the solar garden at time of application.
- **Subscriber types (residential or commercial):** At least 25 per cent of the approved nameplate capacity of the project must be subscribed to by residential customers.
- **Strategy for engaging subscribers:** Explain how you're going to engage subscribers throughout your project.

Section 12: Risk Assessment

DOCUMENT REQUIRED: Using the Risk Assessment Template, identify any issues that may arise throughout the project and how to mitigate them. The template has instructions and examples to help you complete the plan. Be sure to follow the format and guidelines of the template and submit it along with your application form.

Section 13: Final Checklist

DOCUMENT REQUIRED: Use the Final Checklist to confirm that you have completed the application and attached all the supplemental documents. You are required to submit the completed final application checklist with your program application.

Section 14: Affirming Statement

You must affirm that all information provided in the application is true and complete to the best of your knowledge. If any information provided in the application is inaccurate or incomplete, for whatever reason, the department may deny or revoke your approval.

SECTION 4: EVALUATION

Nova Scotia's Community Solar Program application has a rolling intake process, and applications will be reviewed on a first come-first served basis. We will continue to accept applications until we reach program capacity of 100 MWac. However, the Minister reserves the right to close or pause the program to applications at any time.

Evaluation Criteria

Eligible proposals will be assessed using the following table for minimum criteria and using additional scoring indicators to assist the Minister when reviewing applications and approving projects.

Scoring Category	Minimum Criteria	Pass/ Fail	Maximum Points
Application Information			
Applicant is an eligible applicant as per program policies.	Y		N/A
Application is complete and signed.	Y		N/A
Applicant is a community or organization with a mandate to serve equity-deserving group(s) or marginalized community(ies).	N	N/A	5
Partnership Information			
Project is a partnership with one or more communities or organizations representing an equity-deserving group or marginalized community.	N	N/A	5
Ownership model is >51% for the community or organization representing an equity-deserving group or marginalized community.	N	N/A	5
Profit sharing model is >51% for the community or organization representing an equity-deserving group or marginalized community.	N	N/A	5
Project Information			
Project meets the size requirements as per program regulations.	Y		N/A
Applicant provided clear project goals.	Y		N/A

Scoring Category	Minimum Criteria	Pass/ Fail	Maximum Points
Project Site			
Land is demonstrated to be suitable for solar construction.	Y		N/A
Land is owned by project applicant or applicant has provided proof of access, including Crown land use/permits.	Y		N/A
Site selection informed by completed studies (site-selection study, preliminary engineering and design, geotechnical study and preliminary assessment).	Y		N/A
Project site is located on a brownfield, industrial rooftop, or non-arable land.	N	N/A	8
Generation Interconnection Procedures			
Interconnection preliminary assessment completed and attached to application.	Y		N/A
Preliminary assessment is favourable to large-scale solar at the selected site and demonstrates that the solar garden can be interconnected to NSPI's grid.	Y		N/A
Construction Plan			
Construction plan template is complete and identifies reasonable and actionable project steps and timeline.	Y		N/A
Construction plan is well researched and documented.	N	N/A	8
Environmental Considerations and Requirements			
Applicant demonstrates an understanding of environmental considerations and requirements.	Y		N/A
Applicant demonstrates a commitment beyond minimum requirements to environmental preservation and mitigation in relation to the project site.	N	N/A	5
Applicant demonstrates research, knowledge and understanding of species at risk on or around the site and a plan to comply with regulations and requirements.	N	N/A	5

Scoring Category	Minimum Criteria	Pass/ Fail	Maximum Points
Permits and Approvals			
Applicant demonstrates strong understanding of required permits and approvals, and ability to obtain required permits.	Y		N/A
Applicant has obtained preliminary permits and approvals (where possible).	N	N/A	3
Financial Planning			
Applicant has completed the financial planning template.	Y		N/A
Applicant demonstrates strong understanding of financial projections and project viability, and has attached quotes and other supporting documentation to support their financial model.	N	N/A	8
Proposed power purchase rate considers the financial viability of the project, while mitigating cost transfer to rate payers.	N	N/A	10
Applicant demonstrates sound understanding of potential grid upgrades and requirements post DSIS.	N	N/A	5
Applicant has secured capital funding.	N	N/A	5
Applicant has secured financing or provides documentation of favourable potential to secure project financing.	N	N/A	3
Community Engagement and Support			
Applicant has completed community engagement activities.	Y		N/A
Applicant demonstrates community support.	Y		N/A
Applicant demonstrates municipal support.	Y		
Applicant has consulted and engaged diverse communities surrounding the project site, including but not limited to: Mi’kmaw Bands, Chiefs and Councils, and community members	Y		N/A
Applicant has consulted and engaged diverse communities surrounding the project site, including but not limited to: African Nova Scotian communities	Y		N/A
Applicant has consulted and engaged diverse communities surrounding the project site, including but not limited to: Acadian communities	Y		N/A
Applicant has completed a MEKS	N	N/A	5

Scoring Category		Minimum Criteria	Pass/ Fail	Maximum Points
Community Benefits				
Capacity building	Project demonstrates how it will increase capacity for renewables within the community, including increasing knowledge and skills in the renewable energy sector.	Y		N/A
Benefit agreements	Project owner directing a portion of profits back to a particular community or community organization serving marginalized and equity-deserving populations.	Y		N/A
	Applicant demonstrates how the project will enable equitable access to renewable energy by marginalized and equity-deserving populations.	Y		N/A
Economic benefits	Project demonstrates how it will create local jobs, benefit local manufacturers, corporations, vendors, contractors, consultants, and service companies	Y		N/A
Equity, diversity, and inclusion (EDI)	Project demonstrates EDI initiatives within project owner's organization(s), and/or how the project will inform and enhance EDI initiatives.	Y		N/A

Scoring Category	Minimum Criteria	Pass/ Fail	Maximum Points
Subscription Model			
Applicant provided a well-planned and actionable subscription model.	Y		N/A
Applicant demonstrates a plan to engage more than 25% of the nameplate capacity from residential subscribers.	N	N/A	5
Applicant has obtained a warm list of subscribers (10% of the project's nameplate capacity in MWac).	Y		N/A
Applicant has obtained a warm list of subscribers (> 10% of the project's nameplate capacity in MWac).	N	N/A	5
Applicant submitted a plan to engage subscribers from marginalized communities.	N	N/A	5
Risk Assessment			
Project demonstrates a robust understanding of potential risks.	Y		N/A
Project demonstrates knowledgeable and actionable mitigations for identified risks.	Y		N/A
Final Checklist			
Project owner meets all requirements of the application and final checklist	Y		N/A
Affirming Statement			
Signed by designated representative	Y		N/A
	Pass/Fail/Incomplete		**100**

Outcome of Evaluation

Submitting an application does not guarantee acceptance in the program. The Minister will approve, reject, or request more information within 45 business days of reviewing your application, and will provide the decision in writing. If you are approved, you will continue with the following requirements.

Completing the Distribution System Impact Study (DSIS)

If you receive approval from the Department of Natural Resources and Renewables, you will be required to meet the progression milestones identified by NSPI before a **Distribution System Impact Study (DSIS)** can be conducted. These milestones include providing information required for the DSIS and paying any deposits associated with the process. Refer to the Distribution System Impact Study (DSIS) section for additional information.

After receiving program approval, contact NSPI and request to be placed in the DSIS queue. Your place in the queue will determine when your DSIS/facilities study will be conducted.

NSPI will provide you with the scope and estimated cost of conducting the DSIS/facilities study. After you have reviewed this information and paid the deposit, NSPI will complete the study based, in part, on the information provided with your interconnection request. The DSIS/facilities study will include a detailed analysis of the impact of your project, including identified technical and operational requirements for connecting your project to the NSPI distribution system. The study will list the cost and time estimates for completing the required additions and upgrades.

Standard Small Generator Interconnection Agreement (SSGIA)

Once you have reviewed and accepted the interconnection requirements and associated costs, the project-specific terms of the SSGIA can be developed. Those terms include

- the scope of your project
- inspection, testing, authorization, and right of access
- effective date, term, termination, and disconnection
- cost responsibility, milestones, billing, and payment
- project milestones

Follow Your Plan

You are then expected to continue with construction and operation of your community solar garden, adhering to the act, regulations, the PPA, and this guide, including reporting requirements.

Withdrawal from Program

If you decide to withdraw from the program for any reason, including due upgrade costs identified in the DSIS, you must notify the Minister as soon as reasonably possible. Your awarded power purchase rate is not eligible for an increase due to unforeseen circumstances.

If you withdraw from the program, the Minister will request that NSPI revoke your PPA.

SECTION 5: POST-APPROVAL REQUIREMENTS FOR PROJECT OWNERS

It is important to familiarize yourself with ongoing requirements for project owners. Refer to section 25 of the Regulations Respecting the Community Solar Program for more information.

The following provides information and guidance regarding ongoing maintenance and reporting.

Community Solar Garden Maintenance

Your solar garden may require repairs and will require regular maintenance. If you do not have the expertise in your organization to conduct maintenance on your system, contact an experienced professional. Create a maintenance schedule based on manuals, design drawings, system specifications, and expert advice. In addition, it is important to understand any warranties that your supplier provides, including terms and conditions.

Educating yourself and understanding these issues will help to ensure your project is built according to agreement.

It is the responsibility of project owner(s) to construct, operate, and maintain the physical infrastructure of the community solar garden during the term of the PPA.

Reporting Requirements

Before the commercial operation date, you must report the following information to the Minister every six months after your project is approved, or within 30 days of the date of a request for the information:

- your progress in putting the project into service
- number of subscribers recruited and how you are recruiting them
- whether there are any issues regarding project execution and mitigation plans
- any other information the Minister may request

After the commercial operation date, you must report the following information to NSPI at least once every two months for the duration of the PPA:

- the number of subscribers to the project and the size of each subscription
- the total amount of the project's approved nameplate capacity, in kilowatts, that is subscribed to
- any other requirements outlined in the regulations

All reports are to be submitted to Community Solar Program email address at sharedsolar@novascotia.ca

Subscription Management

Your community solar project must meet the following requirements during the term of the PPA:

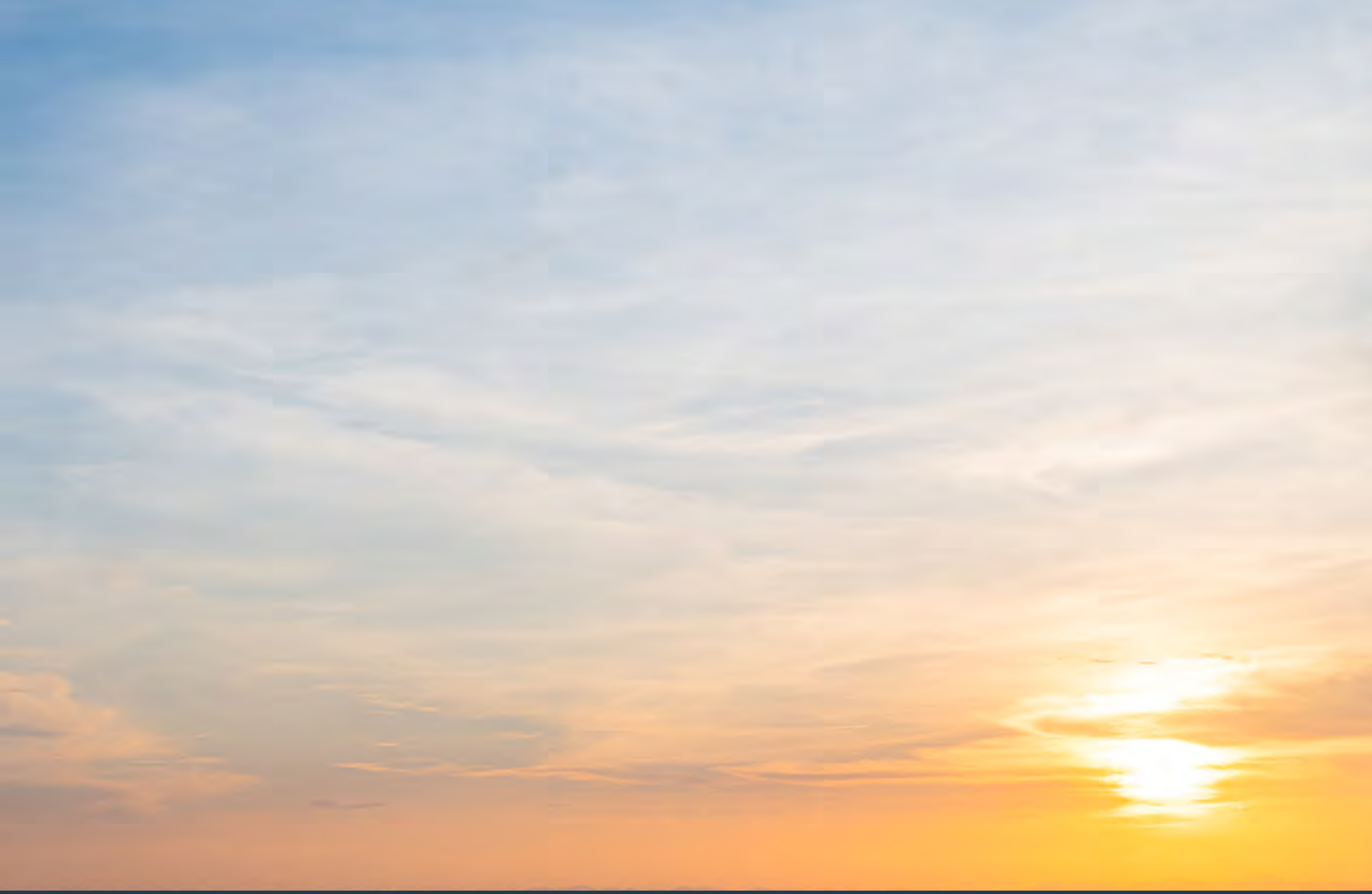
- At least 25 per cent of the approved nameplate capacity of the project must be subscribed to by residential customers
- The project must have at least two subscribers

Annual Subscriber Validation

If you have chosen to prioritize a subscriber group, you must validate your subscription base once a year to ensure all subscribers are within that community. If a subscriber no longer belongs to, or has moved away from, your designated community, it is your responsibility to notify NSPI. NSPI will remove that subscriber from your roster.

Maintaining Subscribers

You are required to achieve and maintain 85 per cent subscribership of the nameplate capacity of your project within one year of your commercial operation date. If you do not reach the 85 per cent mark in one year, your PPA may be revoked, or your power purchase rate may be decreased. The minister will give you 30 days' notice prior to taking any action to give you time to bring your project back into compliance.



NOVA SCOTIA

APPENDIX B

PVSyst Reports

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 1379 Walton Woods Road

Variant: 1379 Walton Woods Road-2 - 3203 kWp MONO-2

Tables on a building

System power: 3203 kWp

1379 Walton Woods Road - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site	Situation		Project settings	
1379 Walton Woods Road	Latitude	45.12 °N	Albedo	0.20
Canada	Longitude	-64.04 °W		
	Altitude	38 m		
	Time zone	UTC-4		

Weather data
1379 Walton Woods Road
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System | **Tables on a building**

PV Field Orientation		Near Shadings	User's needs
Fixed plane		Linear shadings : Fast (table)	Unlimited load (grid)
Tilt/Azimuth	40 / 0 °		

System information

PV Array		Inverters	
Nb. of modules	5772 units	Nb. of units	16 units
Pnom total	3203 kWp	Pnom total	2752 kWac
		Pnom ratio	1.164

Results summary

Produced Energy	4085308 kWh/year	Specific production	1275 kWh/kWp/year	Perf. Ratio PR	88.06 %

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General parameters

Grid-Connected System

Tables on a building

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Sheds configuration
Nb. of sheds 291 units
Identical arrays

Sizes
Sheds spacing 11.0 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 41.6 %

Shading limit angle
Limit profile angle 21.4 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Unlimited load (grid)

PV Array Characteristics

PV module

Manufacturer	Longi Solar
Model	LR5-72HPH-555M G2
(Original PVsyst database)	
Unit Nom. Power	555 Wp
Number of PV modules	5772 units
Nominal (STC)	3203 kWp
Modules	222 string x 26 In series
At operating cond. (50°C)	
Pmpp	2936 kWp
U mpp	984 V
I mpp	2984 A

Inverter

Manufacturer	SMA
Model	Sunny Highpower SHP172-US-21-PEAK3
(Original PVsyst database)	
Unit Nom. Power	172 kWac
Number of inverters	16 units
Total power	2752 kWac
Operating voltage	941-1500 V
Pnom ratio (DC:AC)	1.16

Total PV power

Nominal (STC)	3203 kWp
Total	5772 modules
Module area	14911 m²
Cell area	13841 m²

Total inverter power

Total power	2752 kWac
Number of inverters	16 units
Pnom ratio	1.16

Array losses

Array Soiling Losses
Average loss Fraction 2.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	5.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 5.5 mΩ
Loss Fraction 1.5 % at STC

Module Quality Loss
Loss Fraction -0.8 %

Module mismatch losses
Loss Fraction 2.0 % at MPP

Strings Mismatch loss
Loss Fraction 0.2 %

Array losses

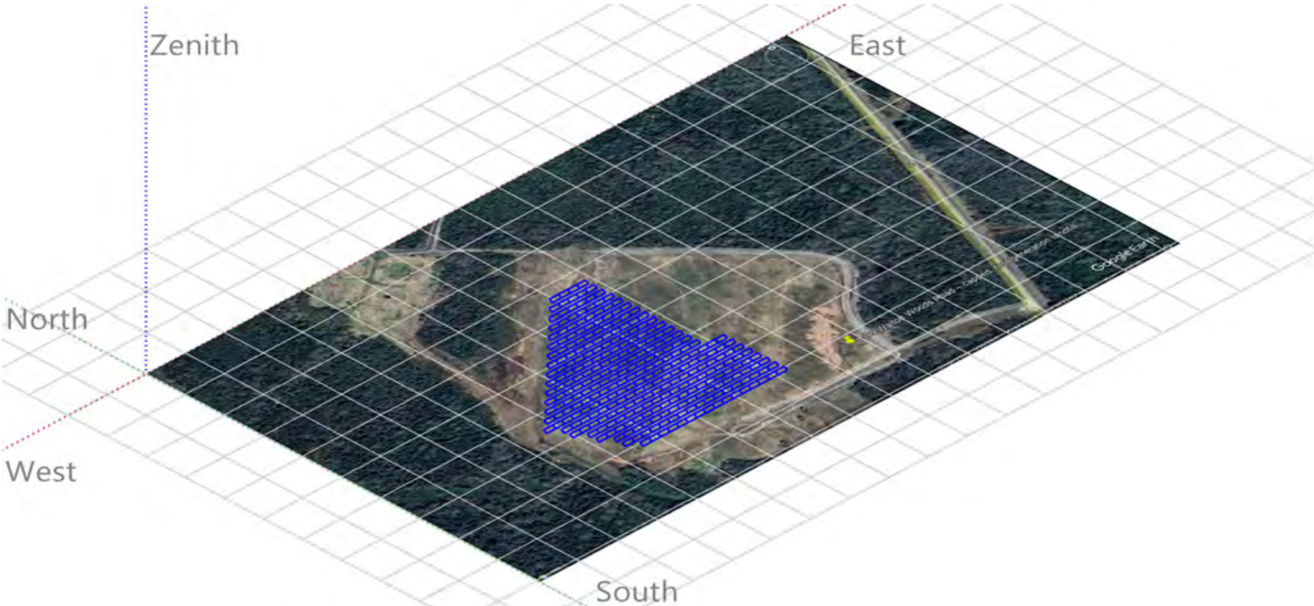
IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

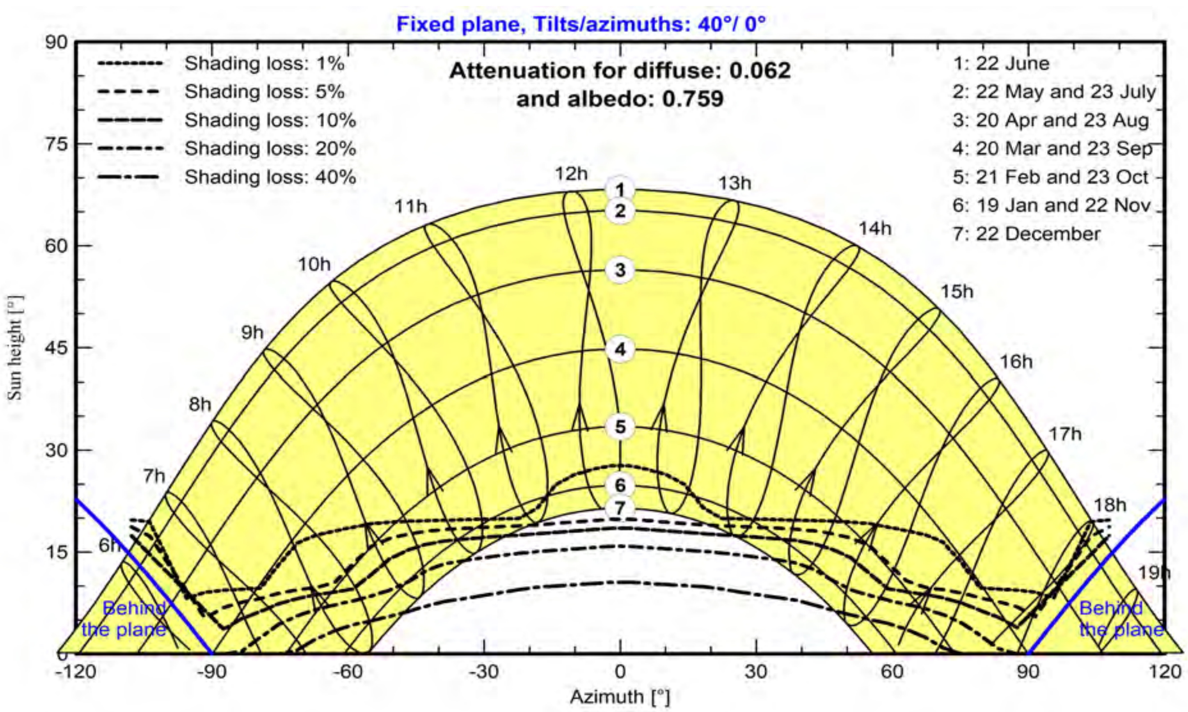
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

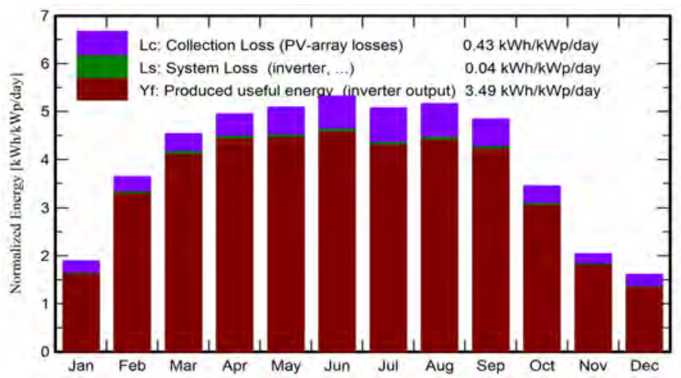


Main results

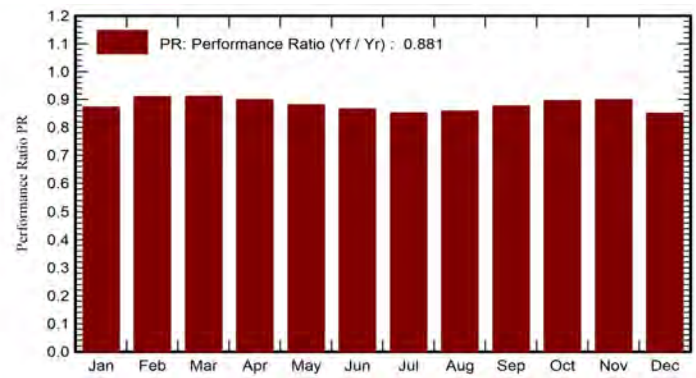
System Production

Produced Energy	4085308 kWh/year	Specific production	1275 kWh/kWp/year
		Perf. Ratio PR	88.06 %

Normalized productions (per installed kWp)



Performance Ratio PR



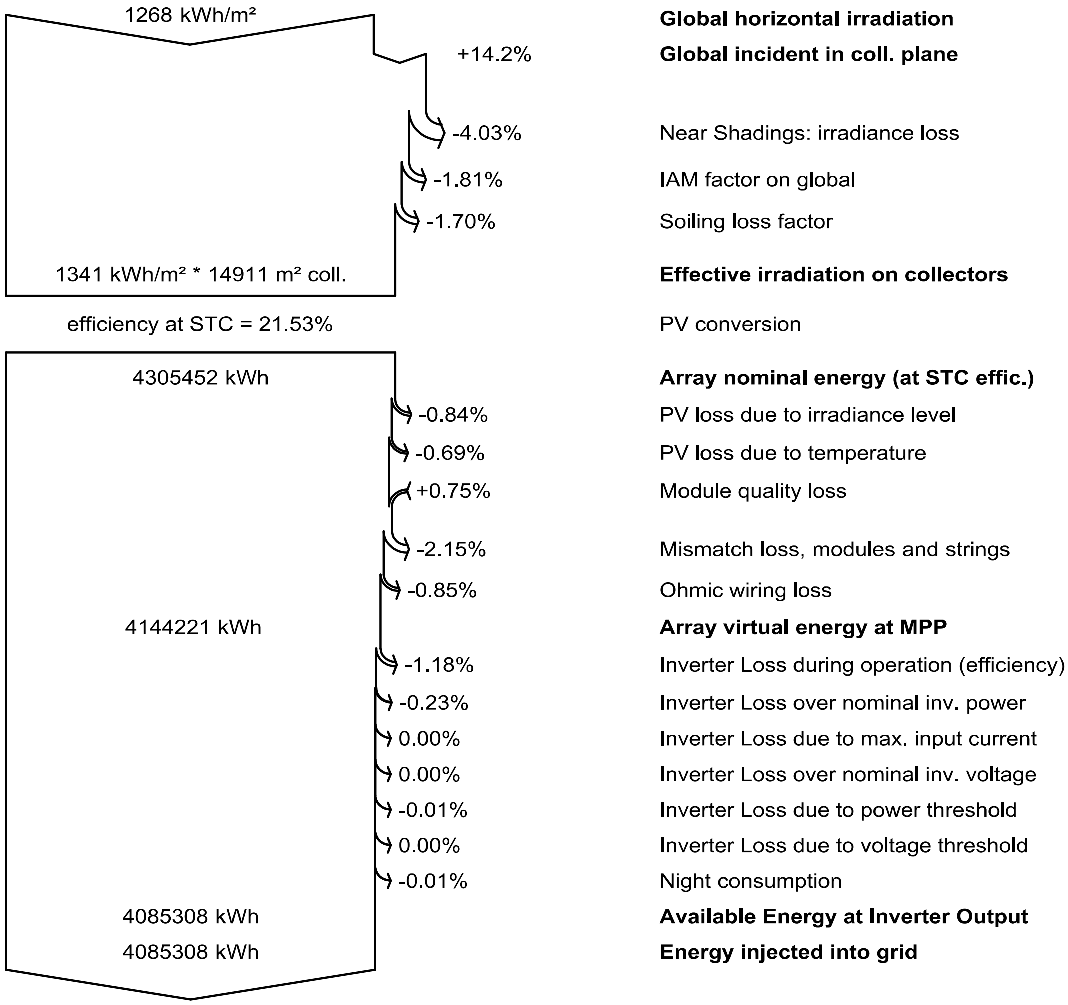
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_Grid kWh	PR ratio
January	36.4	23.95	-5.07	58.6	50.6	165791	163724	0.872
February	63.8	30.19	-4.85	101.8	92.2	300613	296946	0.910
March	107.8	51.07	-1.01	140.7	130.4	416053	410824	0.911
April	133.9	58.70	4.62	148.6	139.7	433753	428182	0.899
May	165.0	81.64	10.48	157.8	146.9	450865	445439	0.881
June	173.4	77.49	15.52	159.6	148.7	447940	442661	0.866
July	168.1	78.06	20.50	157.5	146.6	434888	429819	0.852
August	154.6	74.38	19.98	160.0	149.8	445277	440179	0.859
September	119.5	58.78	15.48	145.3	136.8	412714	407978	0.877
October	75.8	40.82	9.59	106.9	100.5	310442	306808	0.896
November	40.3	26.04	3.90	61.3	56.4	178838	176663	0.899
December	28.9	18.59	-1.41	49.9	42.7	137796	136083	0.851
Year	1267.5	619.71	7.38	1448.1	1341.3	4134970	4085308	0.881

Legends

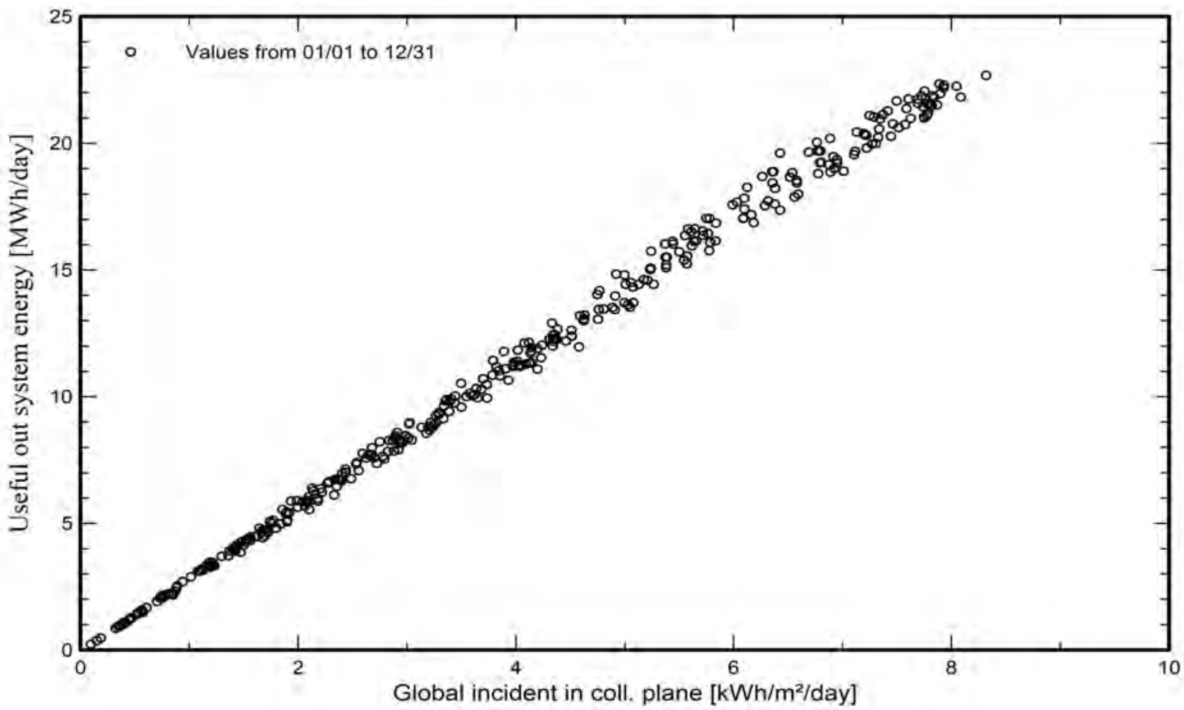
GlobHor	Global horizontal irradiation
DiffHor	Horizontal diffuse irradiation
T_Amb	Ambient Temperature
GlobInc	Global incident in coll. plane
GlobEff	Effective Global, corr. for IAM and shadings
EArray	Effective energy at the output of the array
E_Grid	Energy injected into grid
PR	Performance Ratio

Loss diagram

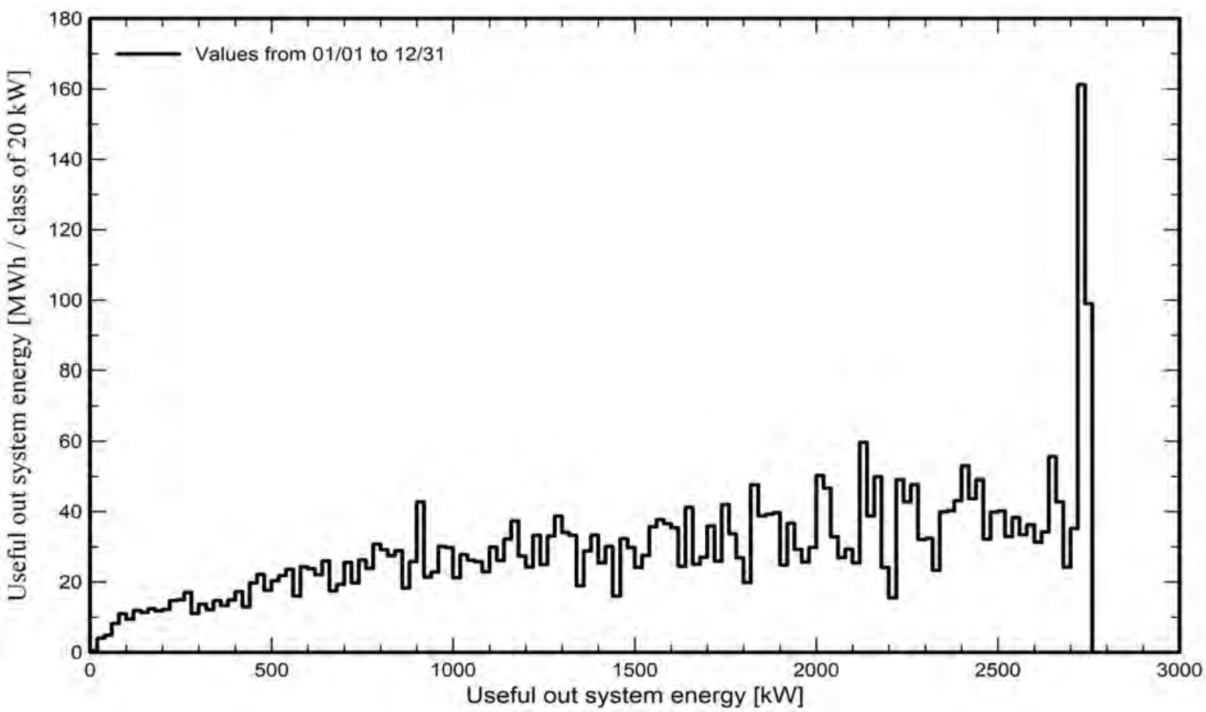


Predef. graphs

Daily Input/Output diagram

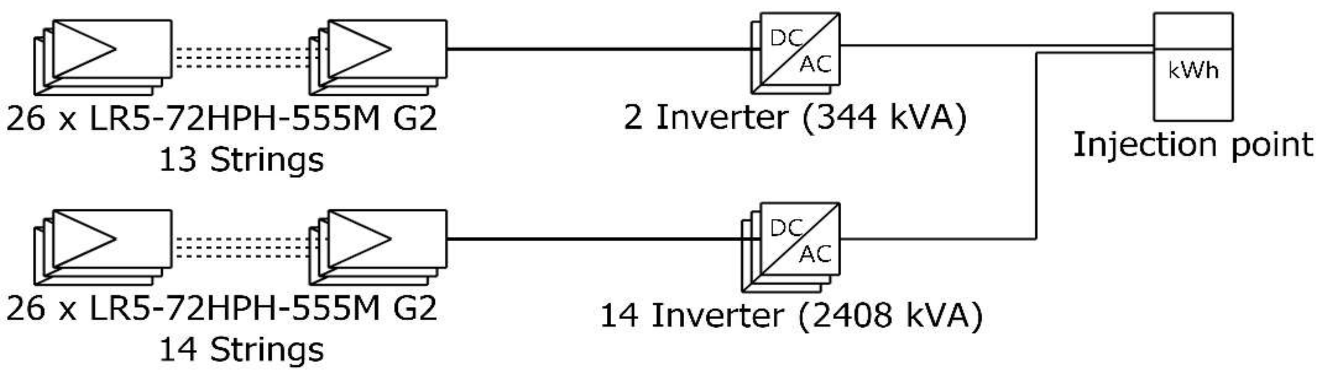


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC5, Simulation date:
08/15/24 13:32
with V7.4.8



PV module	LR5-72HPH-555M G2
Inverter	Sunny Highpower SHP172-US-21-PEAK3
String	26 x LR5-72HPH-555M G2

1379 Walton Woods Road	CBCL Limited (Canada)
VC5 : 1379 Walton Woods Road-2 - 3203 kWp MONO-2	08/15/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 1379 Walton Woods Road

Variant: 1379 Walton Woods Road-2 - 3203 kWp BIFACIAL

Tables on a building

System power: 3203 kWp

1379 Walton Woods Road - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site	Situation		Project settings	
1379 Walton Woods Road	Latitude	45.12 °N	Albedo	0.20
Canada	Longitude	-64.04 °W		
	Altitude	38 m		
	Time zone	UTC-4		

Weather data
1379 Walton Woods Road
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System — **Tables on a building**

PV Field Orientation		Near Shadings	User's needs
Fixed plane		Linear shadings : Fast (table)	Unlimited load (grid)
Tilt/Azimuth	40 / 0 °		

System information

PV Array		Inverters	
Nb. of modules	5824 units	Nb. of units	16 units
Pnom total	3203 kWp	Pnom total	2752 kWac
		Pnom ratio	1.164

Results summary

Produced Energy	4410495 kWh/year	Specific production	1377 kWh/kWp/year	Perf. Ratio PR	95.08 %

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General parameters

Grid-Connected System

Tables on a building

PV Field Orientation

Orientation		**Sheds configuration**		**Models used**	
Fixed plane		Nb. of sheds	291 units	Transposition	Perez
Tilt/Azimuth	40 / 0 °	Identical arrays		Diffuse	Perez, Meteonorm
		Sizes		Circumsolar	separate
		Sheds spacing	11.0 m		
		Collector width	4.58 m		
		Ground Cov. Ratio (GCR)	41.6 %		
		Shading limit angle			
		Limit profile angle	21.4 °		

Horizon	**Near Shadings**	**User's needs**
Free Horizon	Linear shadings : Fast (table)	Unlimited load (grid)

Bifacial system

Model: 2D Calculation, unlimited sheds

Bifacial model geometry		**Bifacial model definitions**	
Sheds spacing	11.00 m	Ground albedo	0.30
Sheds width	4.58 m	Bifaciality factor	70 %
Limit profile angle	21.4 °	Rear shading factor	5.0 %
GCR	41.6 %	Rear mismatch loss	10.0 %
Height above ground	1.50 m	Shed transparent fraction	0.0 %

PV Array Characteristics

PV module		**Inverter**	
Manufacturer	Longi Solar	Manufacturer	SMA
Model	LR5-72HBD-550M G2 Bifacial	Model	Sunny Highpower SHP172-US-21-PEAK3
(Original PVsyst database)		(Original PVsyst database)	
Unit Nom. Power	550 Wp	Unit Nom. Power	172 kWac
Number of PV modules	5824 units	Number of inverters	16 units
Nominal (STC)	3203 kWp	Total power	2752 kWac
Modules	224 string x 26 In series	Operating voltage	941-1500 V
At operating cond. (50°C)		Pnom ratio (DC:AC)	1.16
Pmpp	2935 kWp		
U mpp	982 V		
I mpp	2988 A		

Total PV power		**Total inverter power**	
Nominal (STC)	3203 kWp	Total power	2752 kWac
Total	5824 modules	Number of inverters	16 units
Module area	15045 m²	Pnom ratio	1.16
Cell area	13966 m²		

Array losses

Array Soiling Losses

Average loss Fraction 2.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	5.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%

Array losses

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 5.4 mΩ
Loss Fraction 1.5 % at STC

Module Quality Loss
Loss Fraction -0.8 %

Module mismatch losses
Loss Fraction 2.0 % at MPP

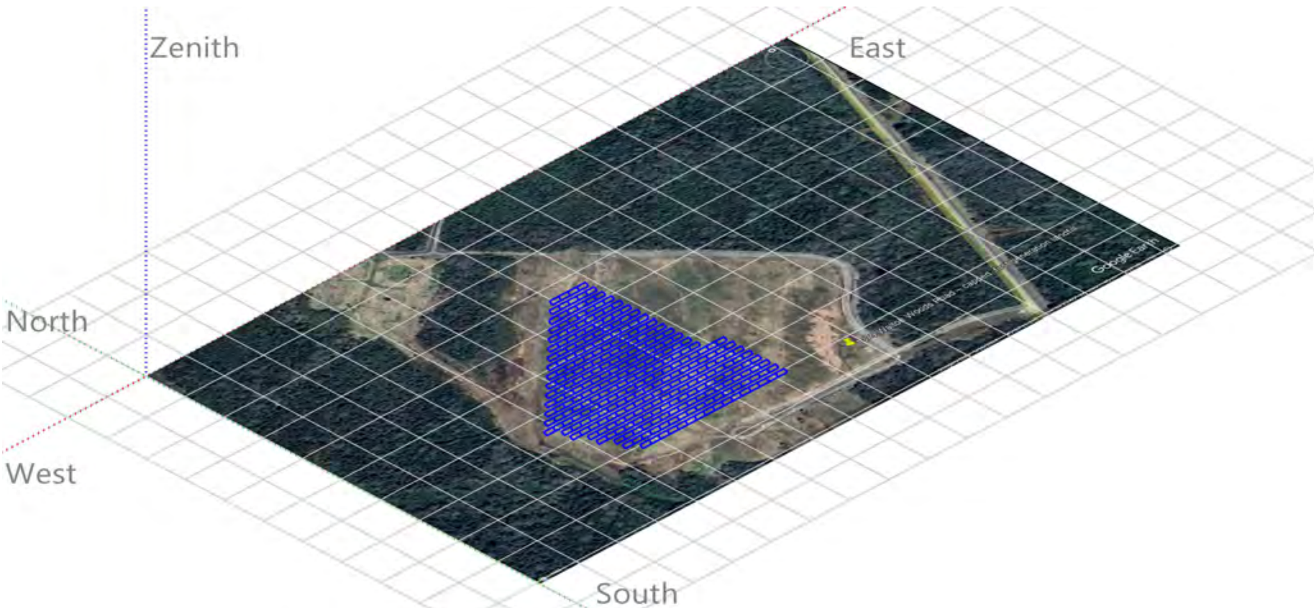
Strings Mismatch loss
Loss Fraction 0.2 %

IAM loss factor
Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

Near shadings parameter

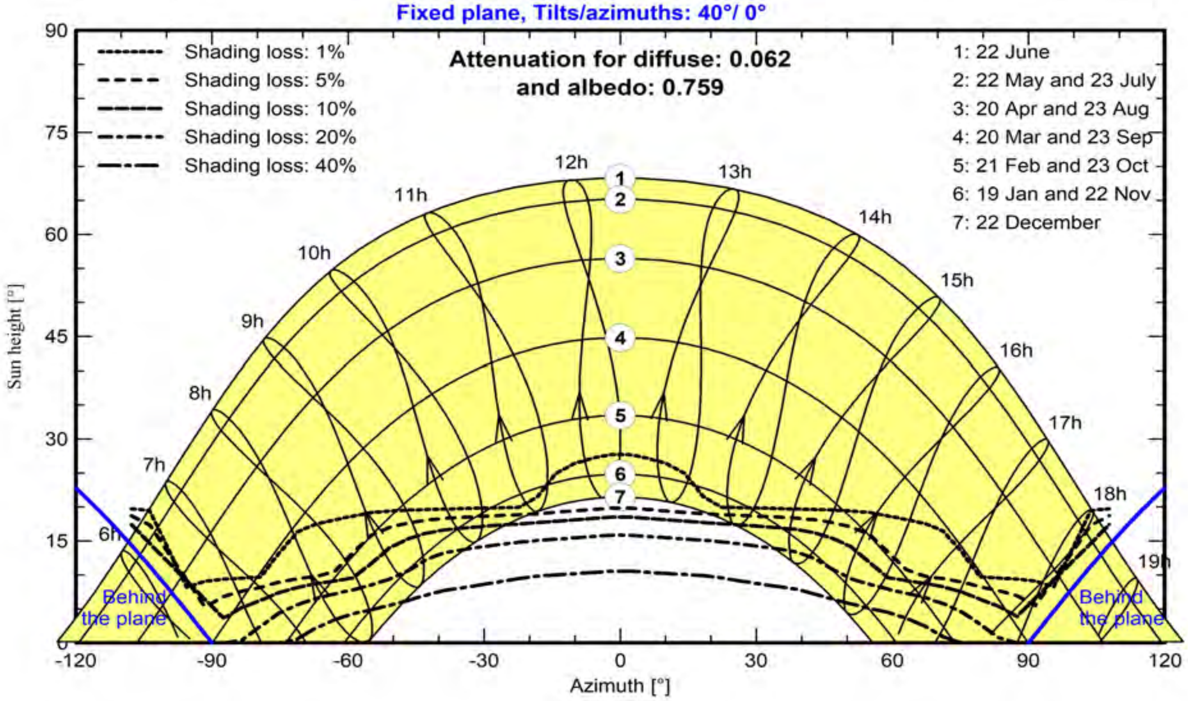
Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

Fixed plane, Tilts/azimuths: 40°/ 0°



Main results

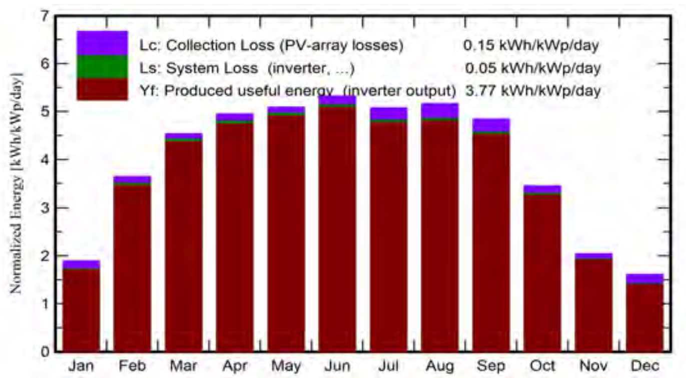
System Production

Produced Energy 4410495 kWh/year

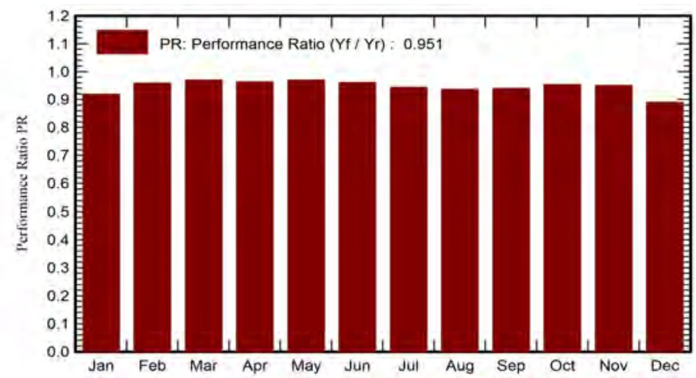
Specific production 1377 kWh/kWp/year

Perf. Ratio PR 95.08 %

Normalized productions (per installed kWp)



Performance Ratio PR



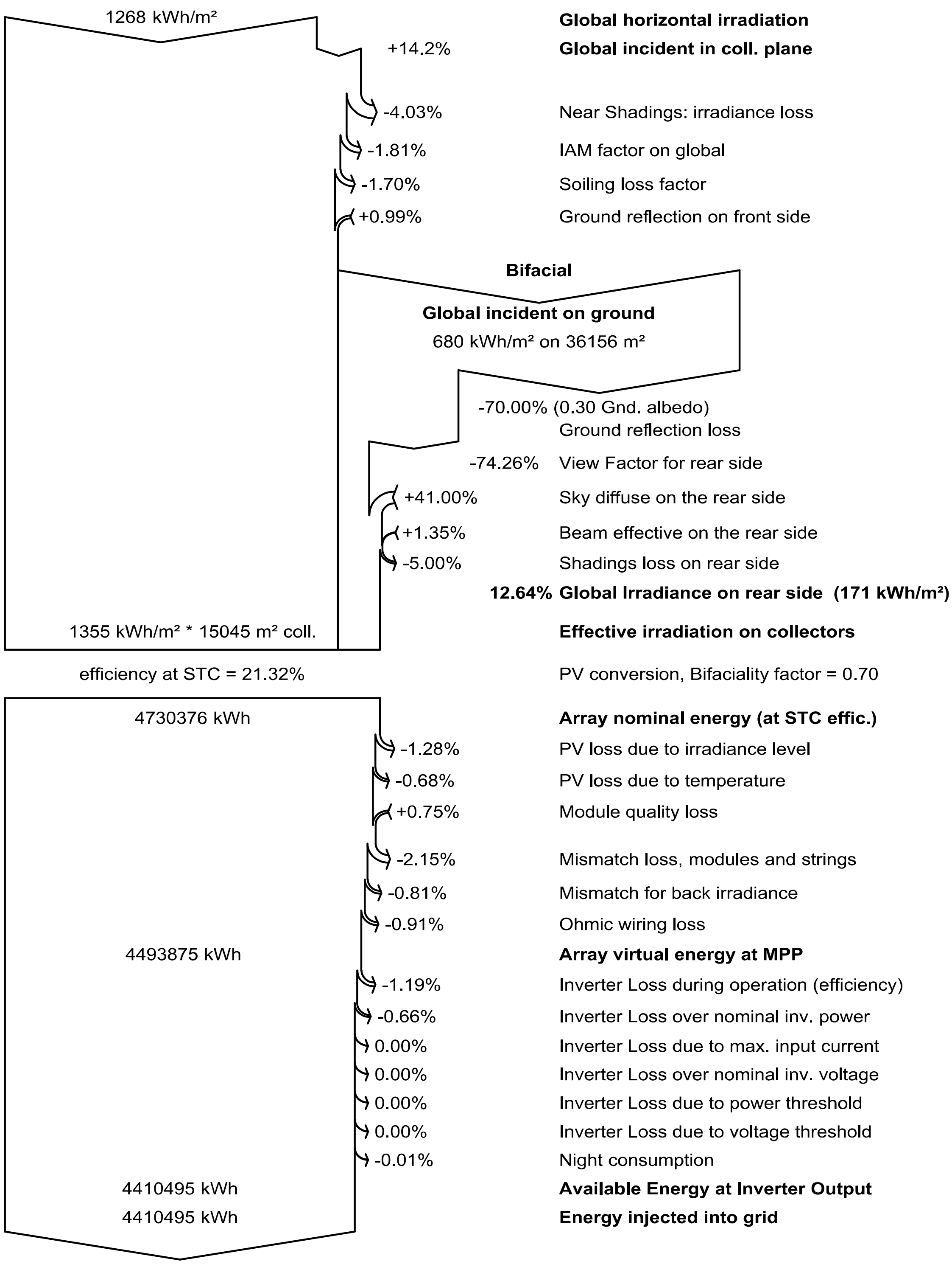
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_Grid kWh	PR ratio
January	36.4	23.95	-5.07	58.6	50.9	174532	172415	0.919
February	63.8	30.19	-4.85	101.8	92.6	316590	312718	0.959
March	107.8	51.07	-1.01	140.7	131.2	442646	437048	0.970
April	133.9	58.70	4.62	148.6	141.1	464276	458332	0.963
May	165.0	81.64	10.48	157.8	148.9	496205	490206	0.970
June	173.4	77.49	15.52	159.6	150.9	497240	491241	0.961
July	168.1	78.06	20.50	157.5	148.7	481797	476092	0.944
August	154.6	74.38	19.98	160.0	151.6	485729	480075	0.936
September	119.5	58.78	15.48	145.3	137.9	442272	437101	0.939
October	75.8	40.82	9.59	106.9	101.1	330351	326473	0.954
November	40.3	26.04	3.90	61.3	56.7	188866	186602	0.950
December	28.9	18.59	-1.41	49.9	42.9	143940	142191	0.890
Year	1267.5	619.71	7.38	1448.1	1354.6	4464445	4410495	0.951

Legends

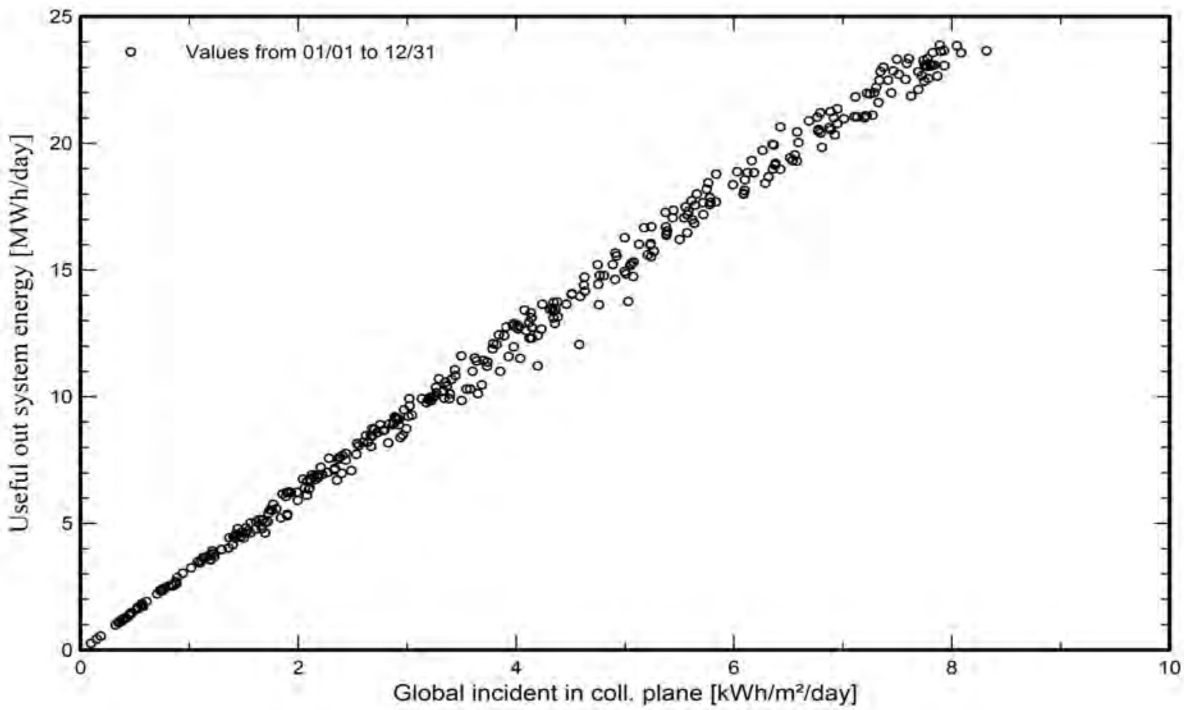
GlobHor	Global horizontal irradiation
DiffHor	Horizontal diffuse irradiation
T_Amb	Ambient Temperature
GlobInc	Global incident in coll. plane
GlobEff	Effective Global, corr. for IAM and shadings
EArray	Effective energy at the output of the array
E_Grid	Energy injected into grid
PR	Performance Ratio

Loss diagram

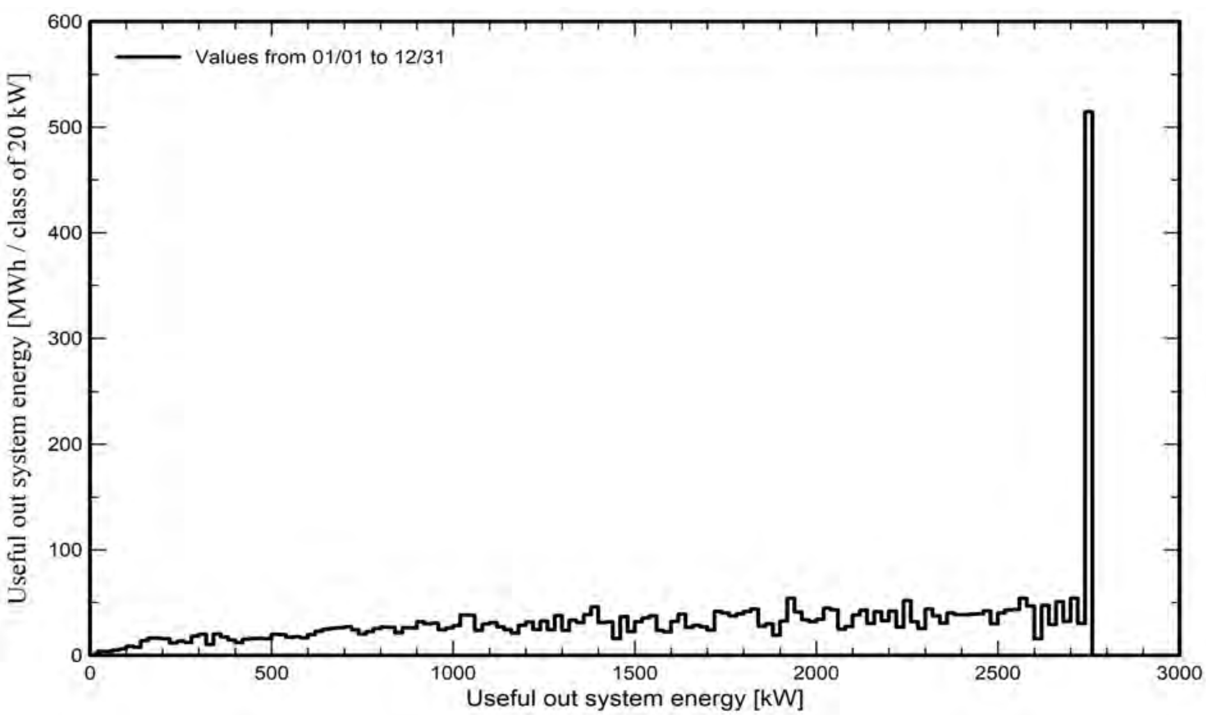


Predef. graphs

Daily Input/Output diagram

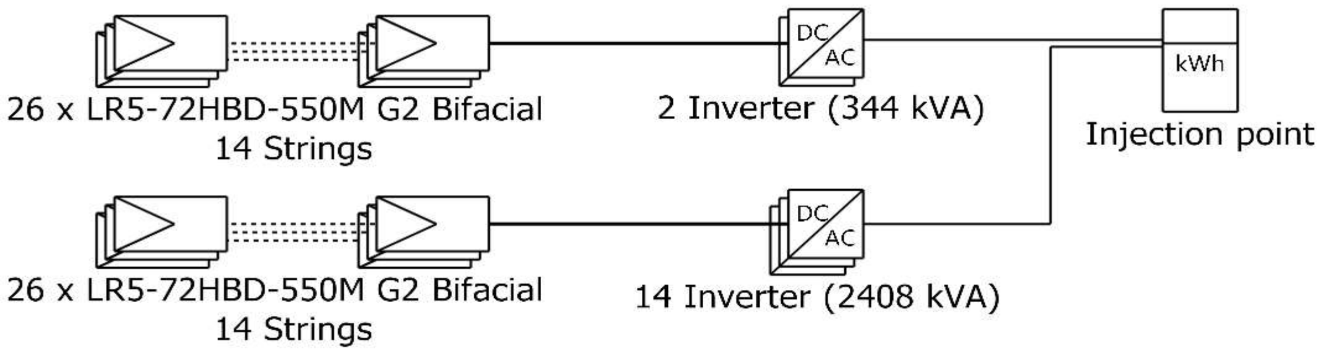


System Output Power Distribution



PVsyst V7.4.8
VC4, Simulation date:
08/15/24 11:58
with V7.4.8

Single-line diagram



PV module	LR5-72HBD-550M G2 Bifacial
Inverter	Sunny Highpower SHP172-US-21-PEAK3
String	26 x LR5-72HBD-550M G2 Bifacial

1379 Walton Woods Road	CBCL Limited (Can ada)
VC4 : 1379 Walton Woods Road-2 - 32 03 kWp BIFACIAL	08/15/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 995 Highway 215:Brooklyn Fire Station and Civic Centre

Variant: Brooklyn Fire Station and Civic Centre w/ground netmetering 195kWp monofacial

Sheds on ground

System power: 195 kWp

Brooklyn Nova Scotia - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site	Situation		Project settings	
Brooklyn Nova Scotia	Latitude	45.00 °N	Albedo	0.20
Canada	Longitude	-64.01 °W		
	Altitude	17 m		
	Time zone	UTC-4		

Weather data
Brooklyn Nova Scotia
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System — **Sheds on ground**

PV Field Orientation		Near Shadings	User's needs
Fixed plane		Linear shadings : Fast (table)	Monthly values
Tilt/Azimuth	40 / 0 °		

System information

PV Array		Inverters	
Nb. of modules	352 units	Nb. of units	3 units
Pnom total	195 kWp	Pnom total	188 kWac
		Pnom ratio	1.042

Results summary

Produced Energy	253891 kWh/year	Specific production	1300 kWh/kWp/year	Perf. Ratio PR	87.97 %
Used Energy	251919 kWh/year			Solar Fraction SF	36.43 %

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General parameters

Grid-Connected System

Sheds on ground

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Sheds configuration
Nb. of sheds 36 units
Sizes
Sheds spacing 11.0 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 41.6 %
Shading limit angle
Limit profile angle 21.4 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
22.0	22.6	20.4	14.7	13.1	11.9	27.8	35.5	26.6	20.0	17.1	20.3	252	MWh/mth

PV Array Characteristics

PV module

Manufacturer Longi Solar
Model LR5-72HPH-555M G2
(Original PVsyst database)
Unit Nom. Power 555 Wp
Number of PV modules 352 units
Nominal (STC) 195 kWp
Modules 22 string x 16 In series
At operating cond. (50°C)
Pmpp 179 kWp
U mpp 605 V
I mpp 296 A

Inverter

Manufacturer SMA
Model Sunny Tripower STP62-US-41-Core1
(Original PVsyst database)
Unit Nom. Power 62.5 kWac
Number of inverters 3 units
Total power 188 kWac
Operating voltage 150-800 V
Pnom ratio (DC:AC) 1.04
Power sharing within this inverter

Total PV power

Nominal (STC) 195 kWp
Total 352 modules
Module area 909 m²
Cell area 844 m²

Total inverter power

Total power 188 kWac
Number of inverters 3 units
Pnom ratio 1.04

Array losses

Array Soiling Losses

Average loss Fraction 1.9 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	4.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%

Thermal Loss factor

Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses

Global array res. 34 mΩ
Loss Fraction 1.5 % at STC

Module Quality Loss

Loss Fraction -0.8 %

Module mismatch losses

Loss Fraction 2.0 % at MPP

Array losses

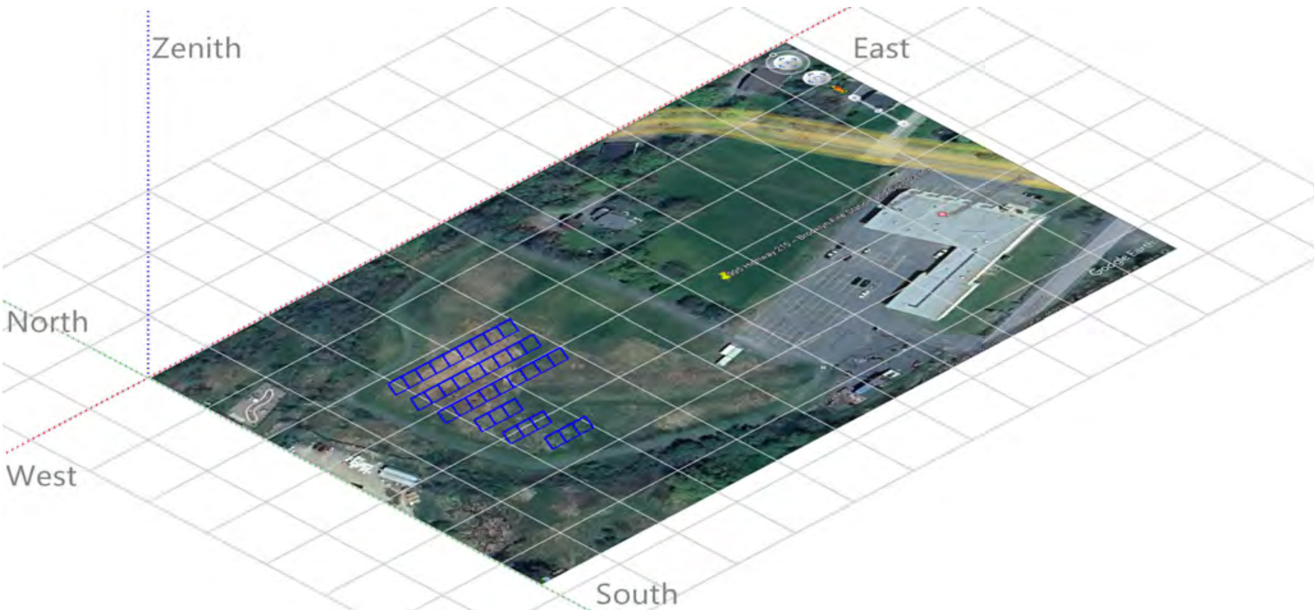
IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

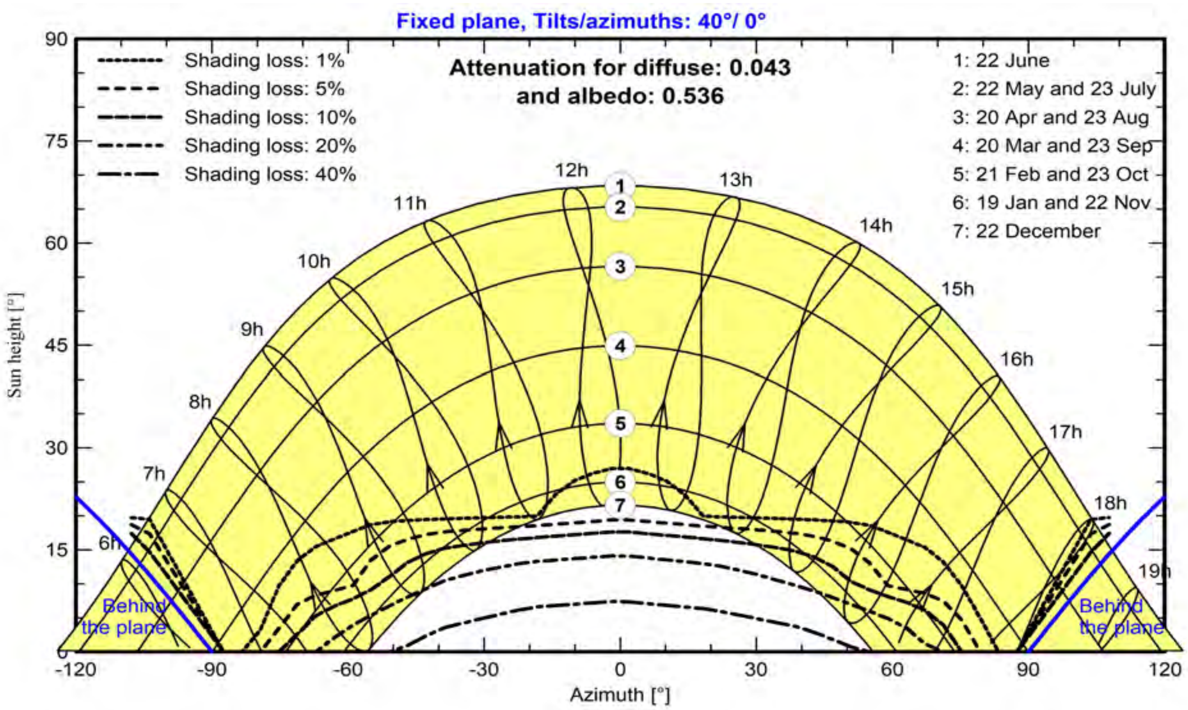
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

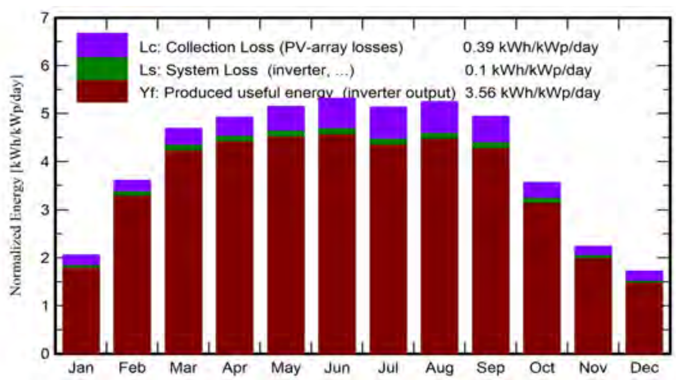


Main results

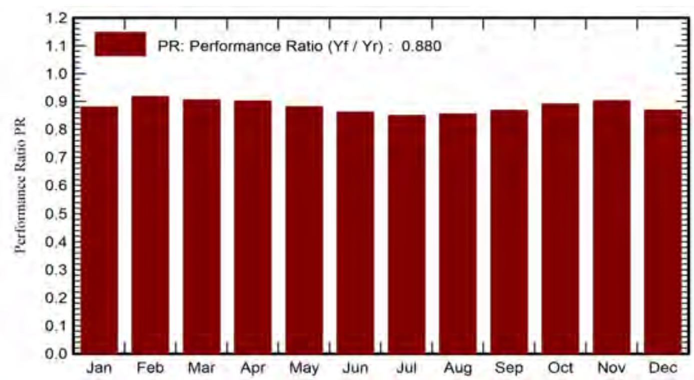
System Production

Produced Energy	253891 kWh/year	Specific production	1300 kWh/kWp/year
Used Energy	251919 kWh/year	Perf. Ratio PR	87.97 %
		Solar Fraction SF	36.43 %

Normalized productions (per installed kWp)



Performance Ratio PR



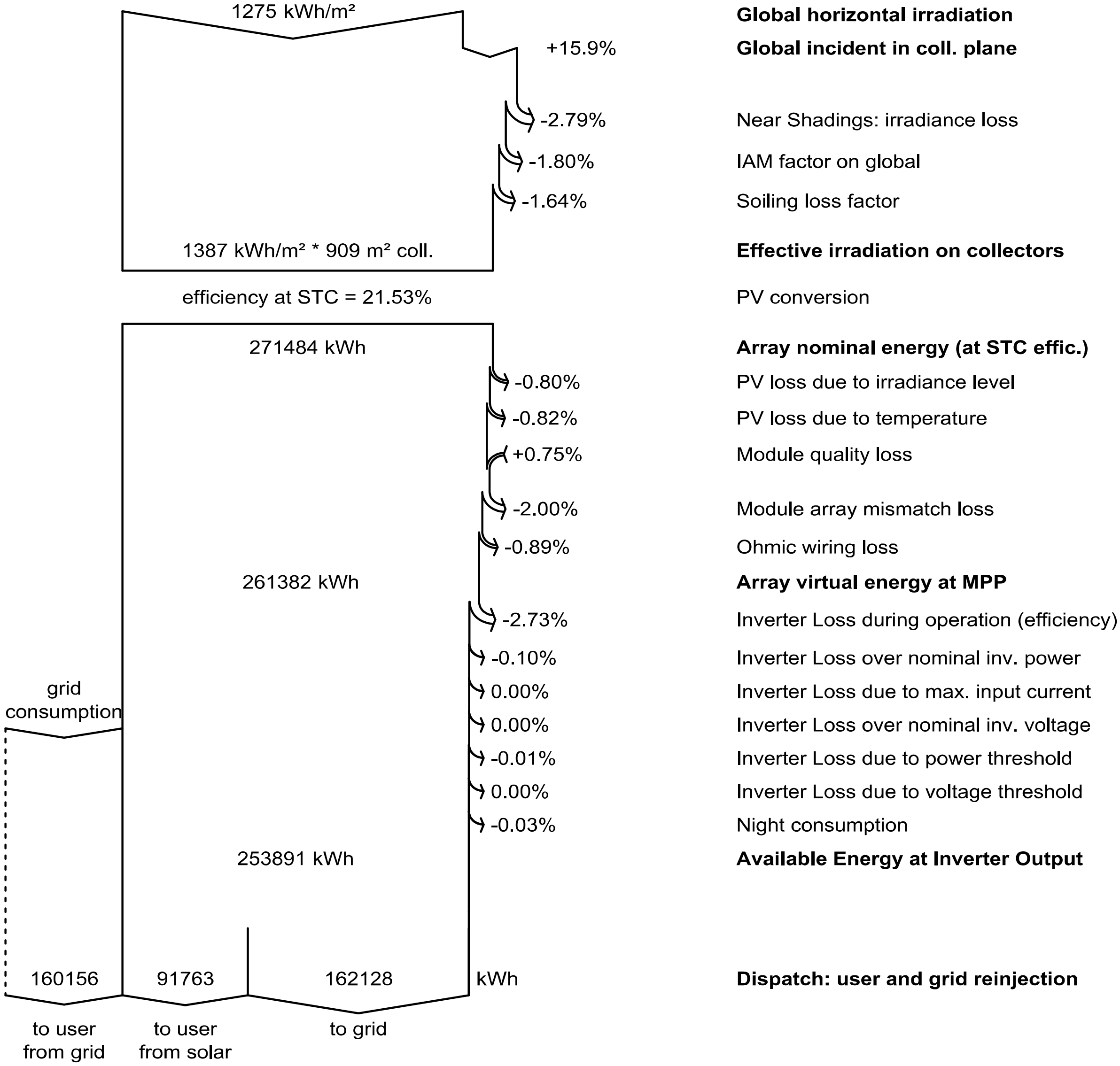
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.1	21.94	-5.11	63.8	56.5	11299	22020	4977	5996	17043
February	64.4	30.86	-4.76	100.8	93.4	18554	22584	7360	10704	15224
March	108.6	42.74	-0.99	145.4	136.3	26447	20442	7932	17800	12509
April	133.7	63.40	4.64	147.6	140.0	26718	14672	6649	19341	8023
May	165.9	88.99	10.49	159.5	150.0	28237	13068	6627	20846	6441
June	173.4	73.92	15.48	159.5	150.4	27614	11851	6033	20803	5818
July	168.8	83.06	20.38	159.2	150.0	27197	27787	12299	14135	15488
August	155.4	72.79	19.84	162.6	154.0	27946	35543	14264	12910	21279
September	120.0	47.57	15.65	148.3	141.3	25876	26585	10219	14935	16365
October	76.6	36.39	9.64	110.2	105.1	19721	19968	6767	12404	13201
November	41.0	24.47	3.95	67.1	62.7	12170	17097	4402	7426	12695
December	29.8	18.40	-1.29	53.3	47.3	9338	20304	4235	4825	16069
Year	1274.8	604.54	7.40	1477.3	1386.9	261117	251919	91763	162128	160156

Legends

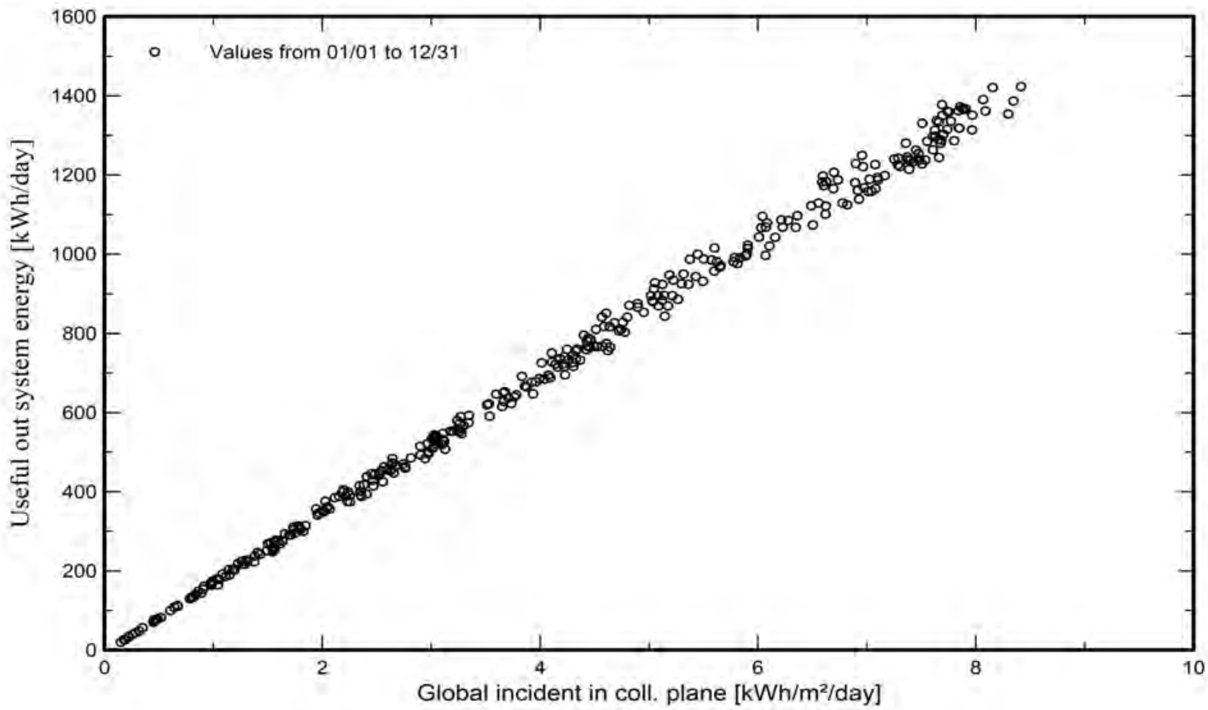
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

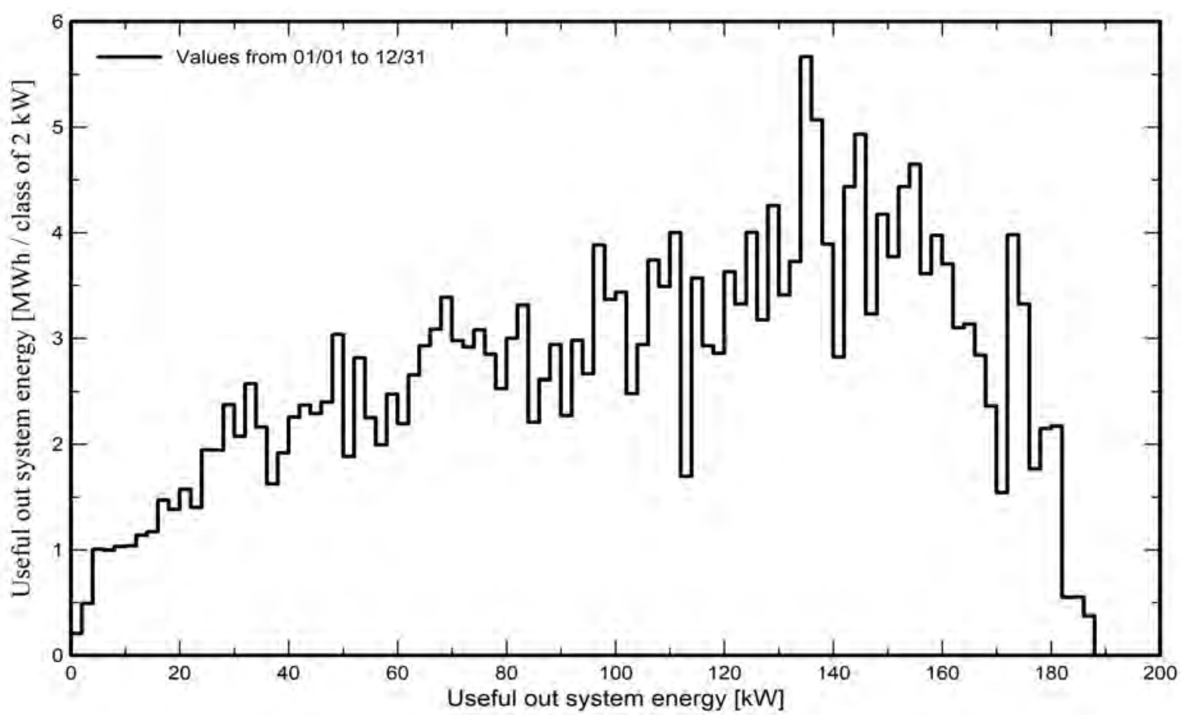


Predef. graphs

Daily Input/Output diagram

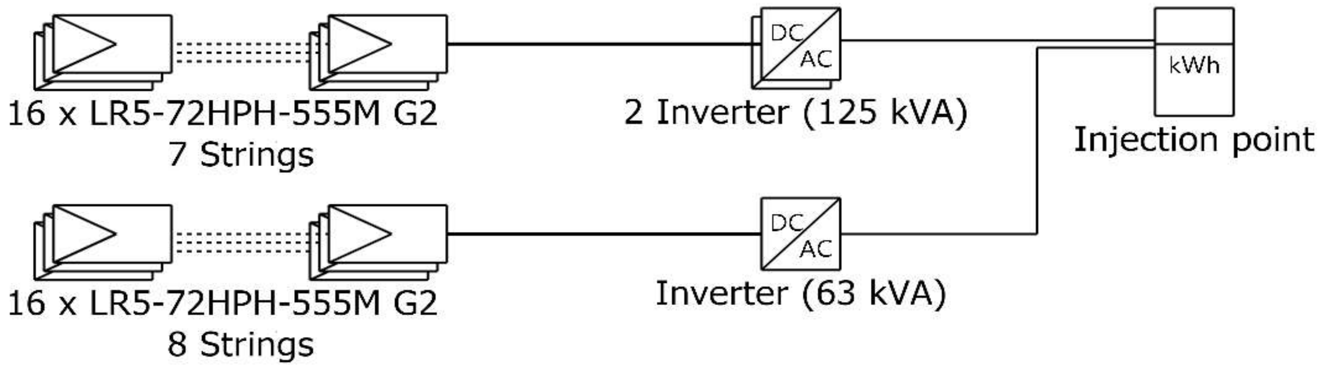


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC6, Simulation date:
08/15/24 12:15
with V7.4.8



PV module	LR5-72HPH-555M G2
Inverter	Sunny Tripower STP62-US-41-Core1
String	16 x LR5-72HPH-555M G2

Brooklyn Fire Station and Civic C entre	CBCL Limited (Can ada)
VC6 : Brooklyn Fire Station and Civic C entre w/ground netmetering 195kWp	08/15/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 995 Highway 215:Brooklyn Fire Station and Civic Centre

Variant: Brooklyn Fire Station and Civic Centre w/ground netmetering 178kWp bifacial

Sheds on ground

System power: 178 kWp

Brooklyn Nova Scotia - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site	Situation		Project settings	
Brooklyn Nova Scotia	Latitude	45.00 °N	Albedo	0.20
Canada	Longitude	-64.01 °W		
	Altitude	17 m		
	Time zone	UTC-4		

Weather data
Brooklyn Nova Scotia
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System — **Sheds on ground**

PV Field Orientation		Near Shadings	User's needs
Fixed plane		Linear shadings : Fast (table)	Monthly values
Tilt/Azimuth	40 / 0 °		

System information

PV Array		Inverters	
Nb. of modules	324 units	Nb. of units	3 units
Pnom total	178 kWp	Pnom total	150 kWac
		Pnom ratio	1.188

Results summary

Produced Energy	247573 kWh/year	Specific production	1389 kWh/kWp/year	Perf. Ratio PR	94.05 %
Used Energy	251919 kWh/year			Solar Fraction SF	36.95 %

Table of contents

Project and results summary 2
General parameters, PV Array Characteristics, System losses 3
Near shading definition - Iso-shadings diagram 5
Main results 6
Loss diagram 7
Predef. graphs 8
Single-line diagram 9

Project: 995 Highway 215:Brooklyn Fire Station and Civic Centre

Variant: Brooklyn Fire Station and Civic Centre w/ground netmetering 178kWp bifacial

CBCL Limited (Canada)

General parameters

Grid-Connected System

Sheds on ground

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Sheds configuration
Nb. of sheds 36 units
Sizes
Sheds spacing 11.0 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 41.6 %
Shading limit angle
Limit profile angle 21.4 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Bifacial system
Model 2D Calculation
unlimited sheds

Bifacial model geometry
Sheds spacing 11.00 m
Sheds width 4.58 m
Limit profile angle 21.4 °
GCR 41.6 %
Height above ground 1.50 m

Bifacial model definitions
Ground albedo 0.30
Bifaciality factor 70 %
Rear shading factor 5.0 %
Rear mismatch loss 10.0 %
Shed transparent fraction 0.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
22.0	22.6	20.4	14.7	13.1	11.9	27.8	35.5	26.6	20.0	17.1	20.3	252	MWh/mth

PV Array Characteristics

PV module
Manufacturer Longi Solar
Model LR5-72HBD-550M G2 Bifacial
(Original PVsyst database)
Unit Nom. Power 550 Wp
Number of PV modules 324 units
Nominal (STC) 178 kWp
Modules 18 string x 18 In series
At operating cond. (50°C)
Pmpp 163 kWp
U mpp 680 V
I mpp 240 A

Inverter
Manufacturer SMA
Model Sunny Tripower STP50-41-Core1
(Original PVsyst database)
Unit Nom. Power 50.0 kWac
Number of inverters 3 units
Total power 150 kWac
Operating voltage 188-800 V
Pnom ratio (DC:AC) 1.19
Power sharing within this inverter

Total PV power
Nominal (STC) 178 kWp
Total 324 modules
Module area 837 m²
Cell area 777 m²

Total inverter power
Total power 150 kWac
Number of inverters 3 units
Pnom ratio 1.19

Array losses

Array Soiling Losses
Average loss Fraction 1.9 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	4.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 47 mΩ
Loss Fraction 1.5 % at STC

Module Quality Loss
Loss Fraction -0.8 %

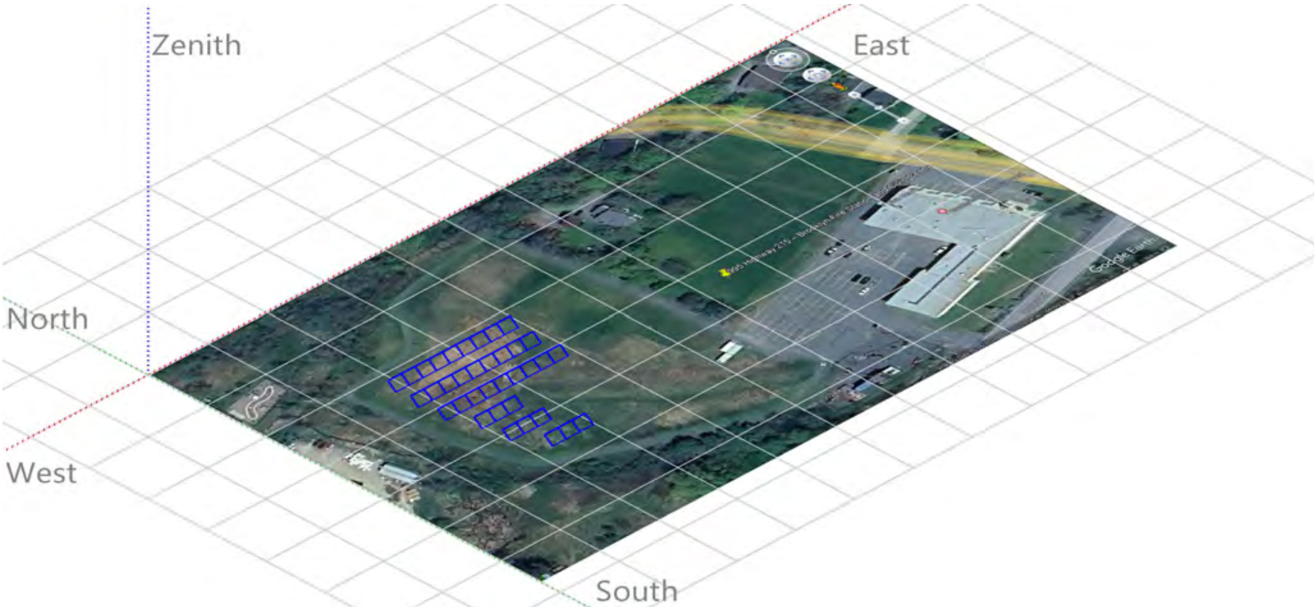
Module mismatch losses
Loss Fraction 2.0 % at MPP

IAM loss factor
Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

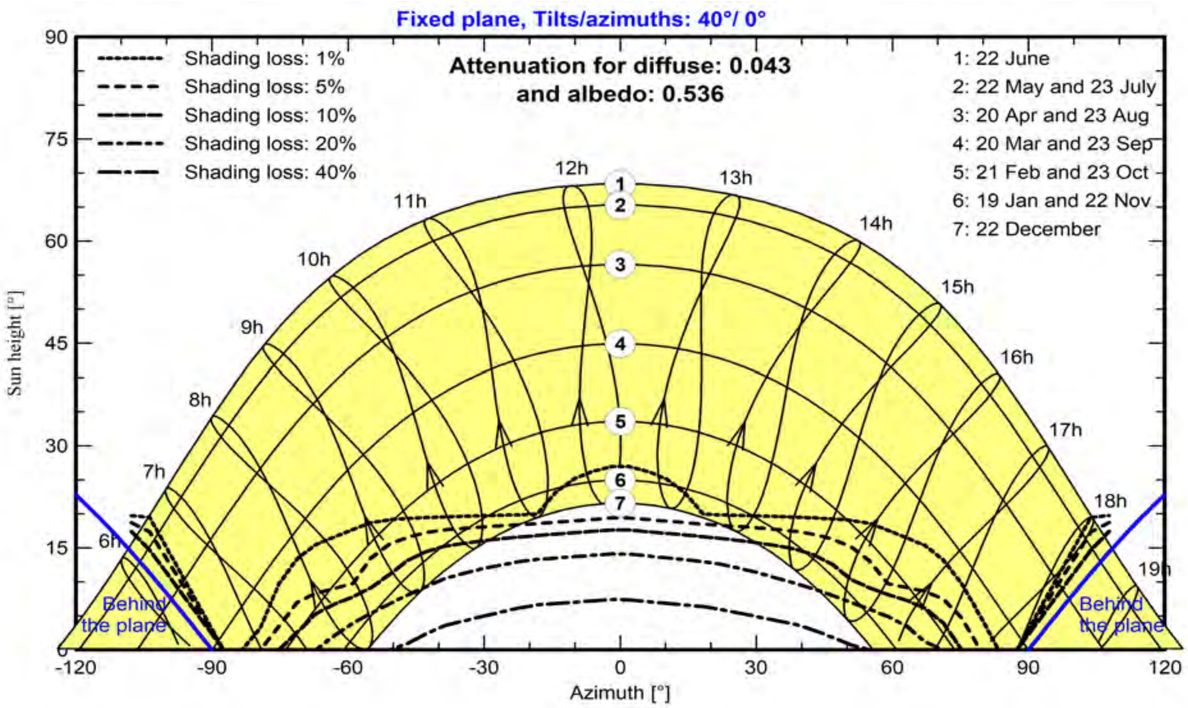
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

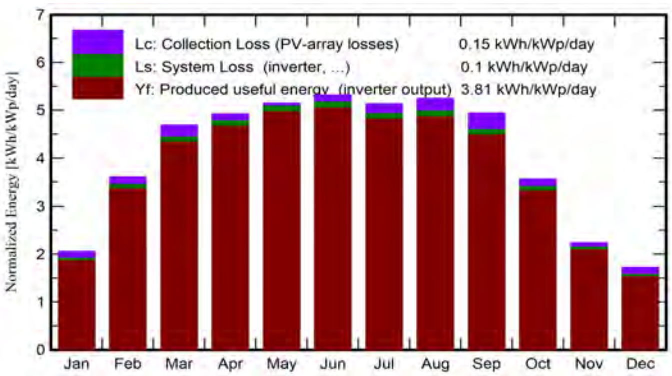


Main results

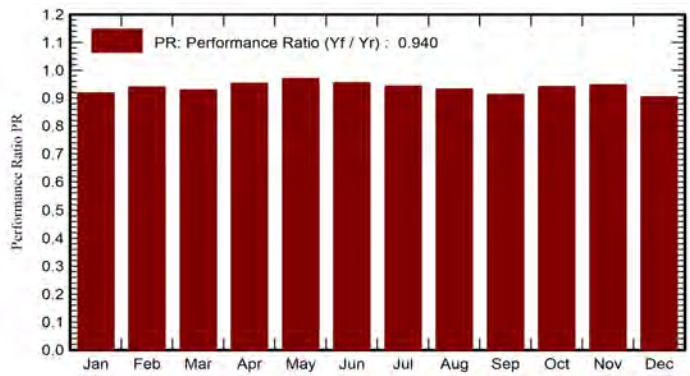
System Production

Produced Energy	247573 kWh/year	Specific production	1389 kWh/kWp/year
Used Energy	251919 kWh/year	Perf. Ratio PR	94.05 %
		Solar Fraction SF	36.95 %

Normalized productions (per installed kWp)



Performance Ratio PR



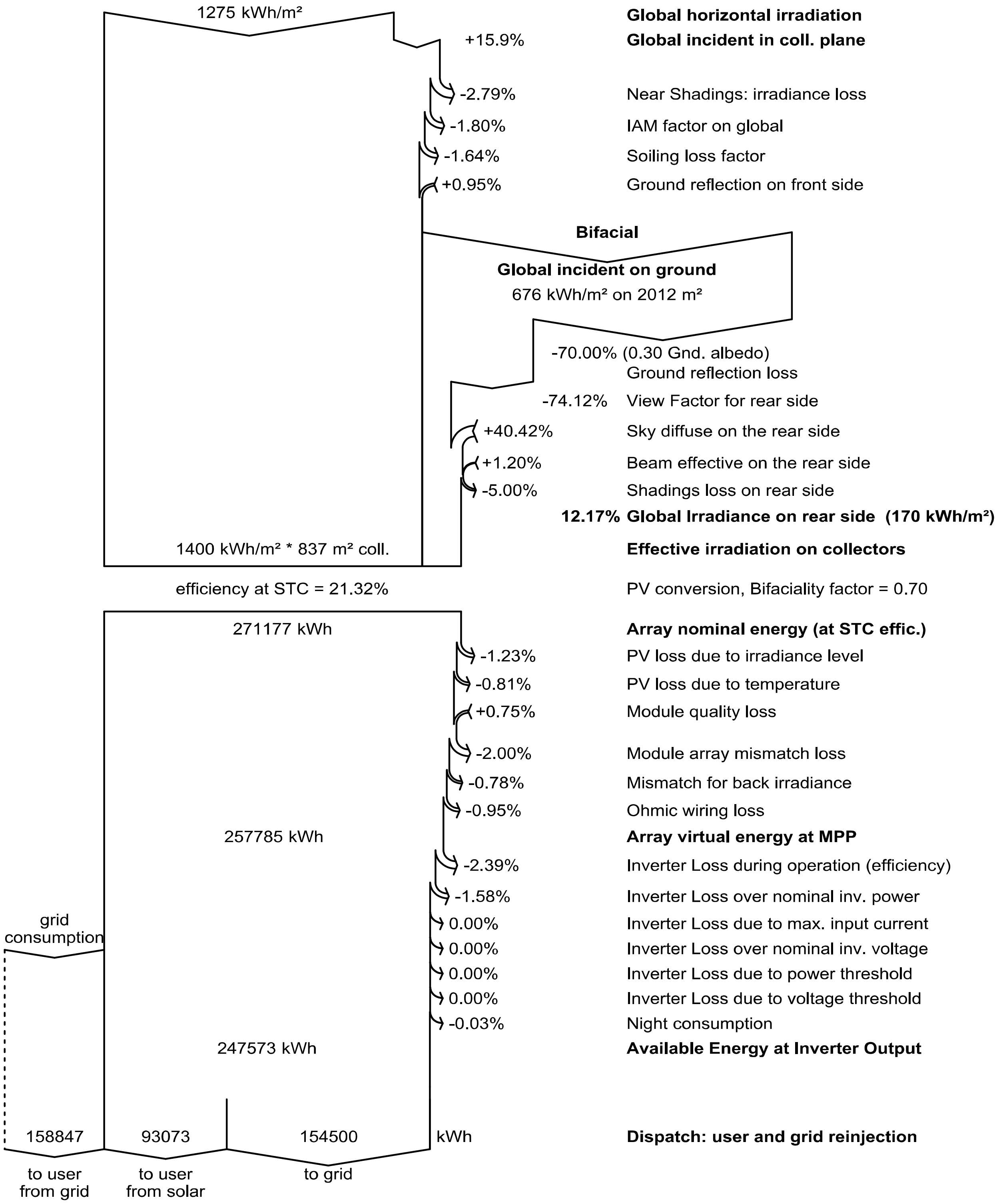
Balances and main results

	GlobHor	DiffHor	T_Amb	GlobInc	GlobEff	EArray	E_User	E_Solar	E_Grid	EFrGrid
	kWh/m²	kWh/m²	°C	kWh/m²	kWh/m²	kWh	kWh	kWh	kWh	kWh
January	37.1	21.94	-5.11	63.8	56.7	10750	22020	5014	5441	17006
February	64.4	30.86	-4.76	100.8	93.8	17329	22584	7285	9611	15299
March	108.6	42.74	-0.99	145.4	137.1	24699	20442	7906	16173	12535
April	133.7	63.40	4.64	147.6	141.4	25714	14672	6720	18358	7951
May	165.9	88.99	10.49	159.5	152.0	28265	13068	6811	20782	6257
June	173.4	73.92	15.48	159.5	152.6	27810	11851	6315	20824	5536
July	168.8	83.06	20.38	159.2	152.2	27403	27787	12689	14068	15098
August	155.4	72.79	19.84	162.6	155.8	27686	35543	14509	12530	21034
September	120.0	47.57	15.65	148.3	142.4	24724	26585	10314	13815	16270
October	76.6	36.39	9.64	110.2	105.7	18945	19968	6815	11665	13153
November	41.0	24.47	3.95	67.1	62.9	11623	17097	4437	6887	12660
December	29.8	18.40	-1.29	53.3	47.5	8850	20304	4258	4347	16047
Year	1274.8	604.54	7.40	1477.3	1400.1	253800	251919	93073	154500	158847

Legends

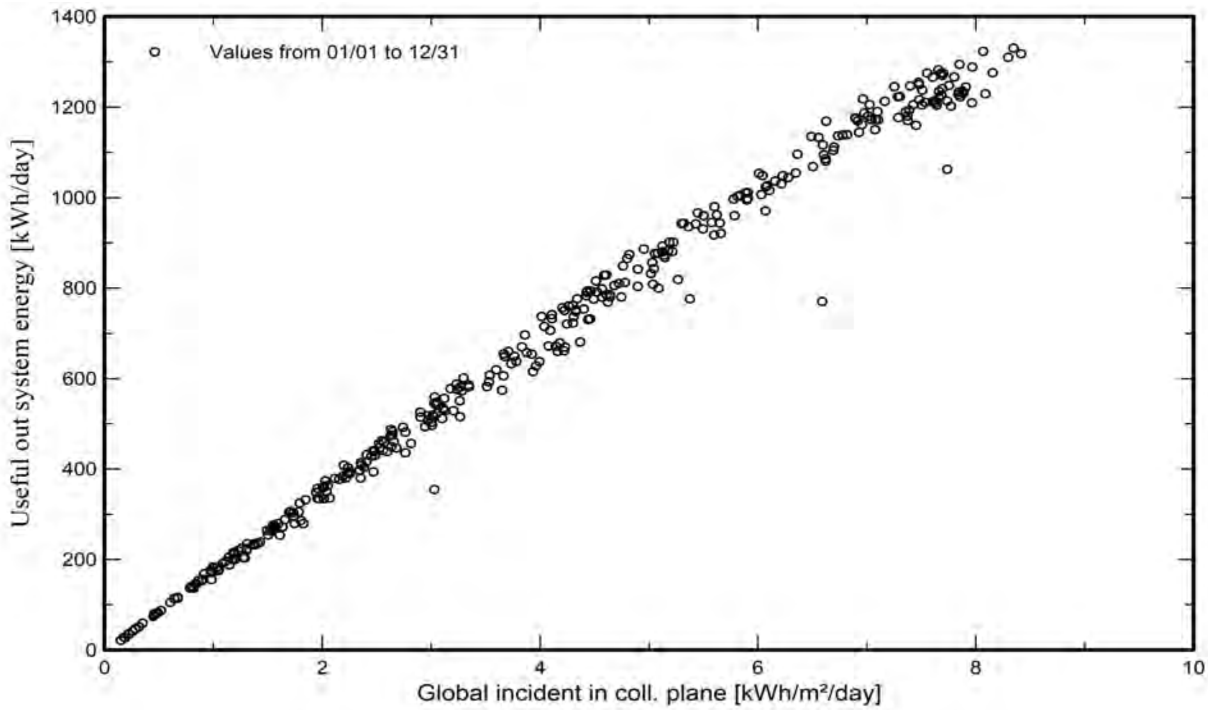
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

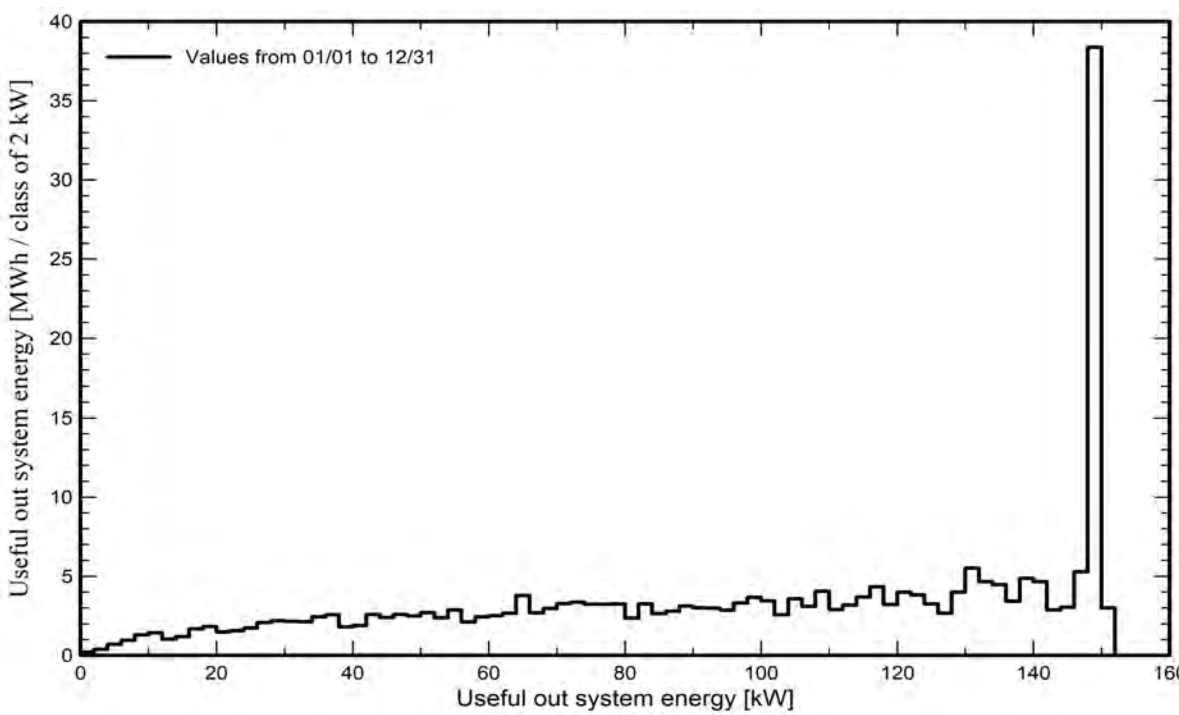


Predef. graphs

Daily Input/Output diagram

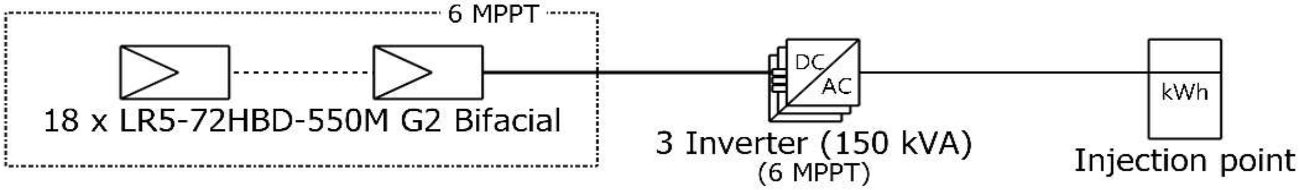


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC5, Simulation date:
08/15/24 12:11
with V7.4.8



PV module	LR5-72HBD-550M G2 Bifacial
Inverter	Sunny Tripower STP50-41-Core1
String	18 x LR5-72HBD-550M G2 Bifacial

Brooklyn Fire Station and Civic C entre	CBCL Limited (Can ada)
VC5 : Brooklyn Fire Station and Civic C entre w/ground netmetering 178kWp b	08/15/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 995 Highway 215:Brooklyn Fire Station and Civic Centre

Variant: Brooklyn Fire Station and Civic Centre w/ground netmetering 140 kWp roof

Sheds on a building

System power: 140 kWp

Brooklyn Nova Scotia - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site	Situation		Project settings	
Brooklyn Nova Scotia	Latitude	45.00 °N	Albedo	0.20
Canada	Longitude	-64.01 °W		
	Altitude	17 m		
	Time zone	UTC-4		

Weather data
Brooklyn Nova Scotia
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System — **Sheds on a building**

PV Field Orientation		Near Shadings	User's needs
Fixed plane		Linear shadings : Fast (table)	Monthly values
Tilt/Azimuth	10 / -17.1 °		

System information

PV Array		Inverters	
Nb. of modules	252 units	Nb. of units	2 units
Pnom total	140 kWp	Pnom total	125 kWac
		Pnom ratio	1.119

Results summary

Produced Energy	164699 kWh/year	Specific production	1178 kWh/kWp/year	Perf. Ratio PR	86.15 %
Used Energy	251919 kWh/year			Solar Fraction SF	34.05 %

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General parameters

Grid-Connected System — **Sheds on a building**

PV Field Orientation

Orientation

Fixed plane

Tilt/Azimuth 10 / -17.1 °

Sheds configuration

Nb. of sheds 35 units

Sizes

Sheds spacing 1.45 m

Collector width 1.13 m

Ground Cov. Ratio (GCR) 78.2 %

Top inactive band 0.02 m

Bottom inactive band 0.02 m

Shading limit angle

Limit profile angle 32.6 °

Models used

Transposition Perez

Diffuse Perez, Meteonorm

Circumsolar separate

Horizon

Free Horizon

Near Shadings

Linear shadings : Fast (table)

User's needs

Monthly values

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
22.0	22.6	20.4	14.7	13.1	11.9	27.8	35.5	26.6	20.0	17.1	20.3	252	MWh/mth

PV Array Characteristics

PV module

Manufacturer Longi Solar

Model LR5-72HPH-555M G2

(Original PVsyst database)

Unit Nom. Power 555 Wp

Number of PV modules 252 units

Nominal (STC) 140 kWp

Modules 14 string x 18 In series

At operating cond. (50°C)

Pmpp 128 kWp

U mpp 681 V

I mpp 188 A

Inverter

Manufacturer SMA

Model Sunny Tripower STP62-US-41-Core1

(Original PVsyst database)

Unit Nom. Power 62.5 kWac

Number of inverters 2 units

Total power 125 kWac

Operating voltage 150-800 V

Pnom ratio (DC:AC) 1.12

Power sharing within this inverter

Total PV power

Nominal (STC) 140 kWp

Total 252 modules

Module area 651 m²

Cell area 604 m²

Total inverter power

Total power 125 kWac

Number of inverters 2 units

Pnom ratio 1.12

Array losses

Array Soiling Losses

Average loss Fraction 2.6 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
7.0%	7.0%	5.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	4.0%

Thermal Loss factor

Module temperature according to irradiance

Uc (const) 20.0 W/m²K

Uv (wind) 0.0 W/m²K/m/s

DC wiring losses

Global array res. 60 mΩ

Loss Fraction 1.5 % at STC

Module Quality Loss

Loss Fraction -0.8 %

Array losses

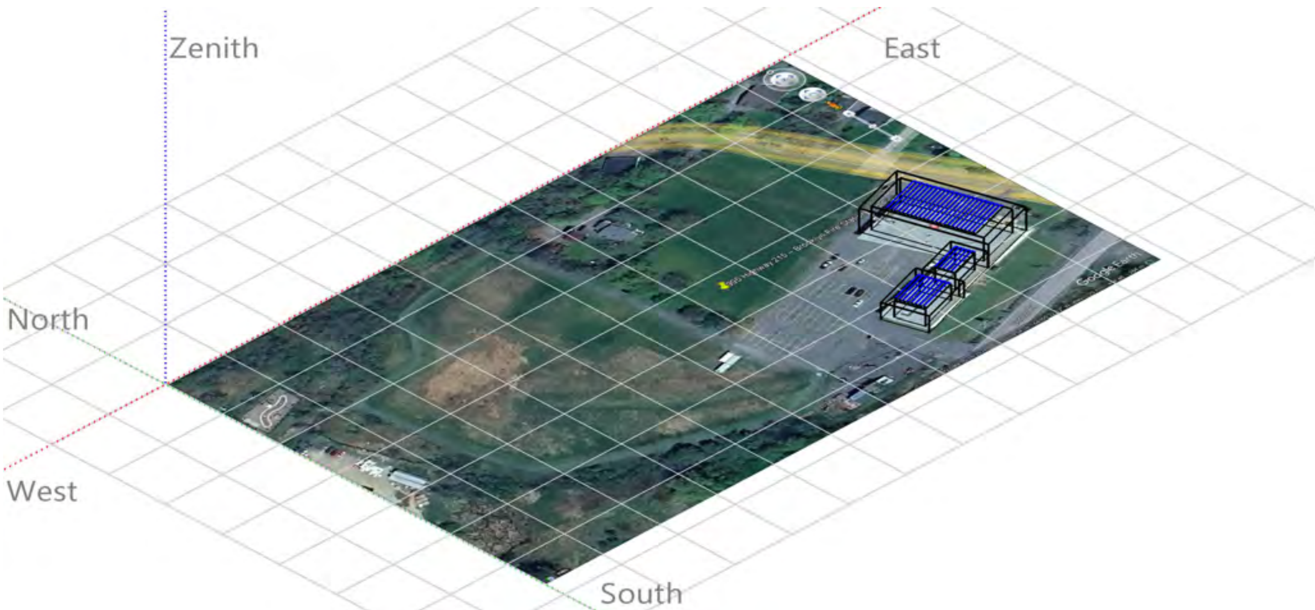
Module mismatch losses
Loss Fraction 2.0 % at MPP

IAM loss factor
Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

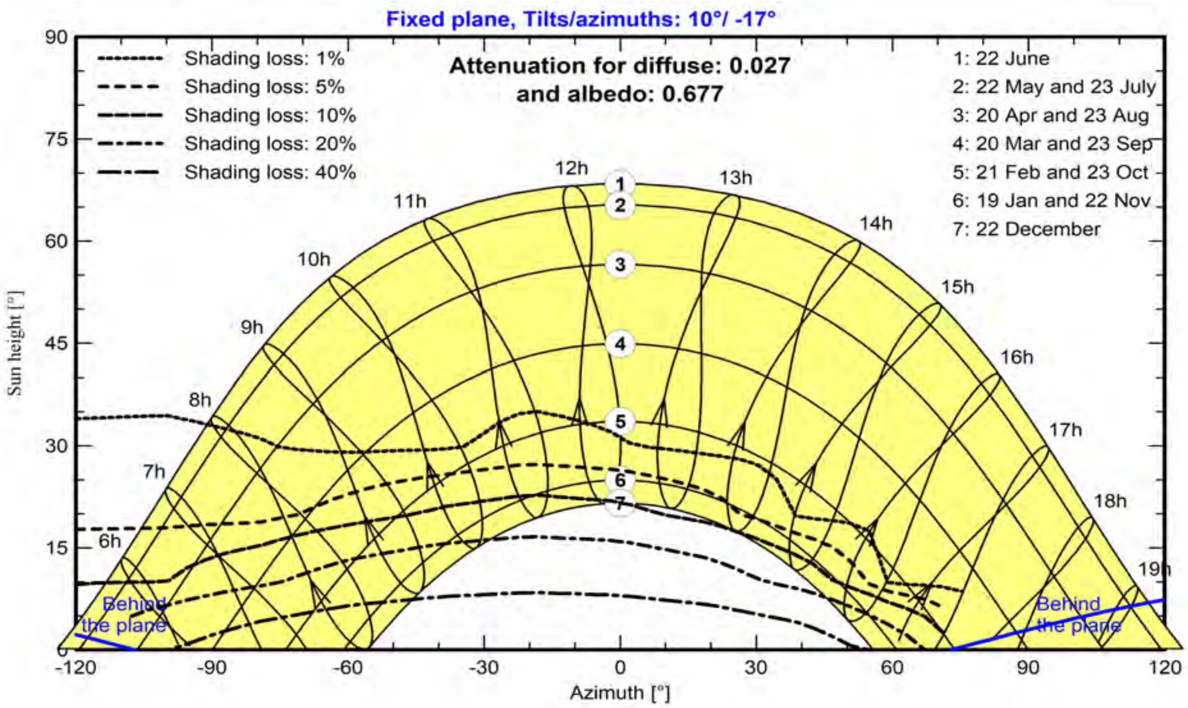
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

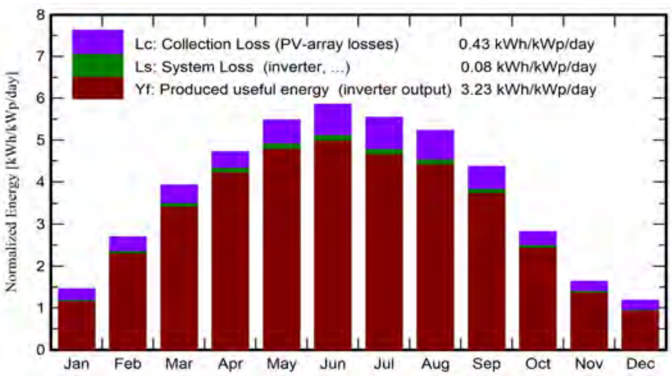


Main results

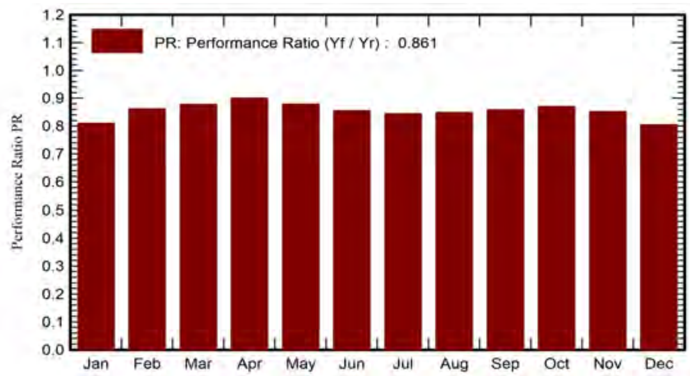
System Production

Produced Energy	164699 kWh/year	Specific production	1178 kWh/kWp/year
Used Energy	251919 kWh/year	Perf. Ratio PR	86.15 %
		Solar Fraction SF	34.05 %

Normalized productions (per installed kWp)



Performance Ratio PR



Balances and main results

	GlobHor	DiffHor	T_Amb	GlobInc	GlobEff	EArray	E_User	E_Solar	E_Grid	EFrGrid
	kWh/m²	kWh/m²	°C	kWh/m²	kWh/m²	kWh	kWh	kWh	kWh	kWh
January	37.1	21.94	-5.11	45.1	36.8	5246	22020	4097	1010	17923
February	64.4	30.86	-4.76	75.5	65.6	9309	22584	6330	2764	16254
March	108.6	42.74	-0.99	121.6	110.6	15304	20442	7295	7638	13147
April	133.7	63.40	4.64	141.6	135.2	18280	14672	6551	11275	8121
May	165.9	88.99	10.49	169.8	162.0	21414	13068	6666	14209	6402
June	173.4	73.92	15.48	175.6	168.3	21565	11851	6116	14881	5735
July	168.8	83.06	20.38	171.8	164.3	20833	27787	12162	8123	15625
August	155.4	72.79	19.84	162.1	155.1	19755	35543	13620	5621	21923
September	120.0	47.57	15.65	131.1	124.7	16168	26585	9470	6279	17114
October	76.6	36.39	9.64	87.4	81.8	10930	19968	6076	4572	13892
November	41.0	24.47	3.95	49.0	43.3	5992	17097	3967	1867	13130
December	29.8	18.40	-1.29	36.5	30.1	4231	20304	3422	686	16882
Year	1274.8	604.54	7.40	1367.0	1277.9	169027	251919	85772	78927	166147

Legends

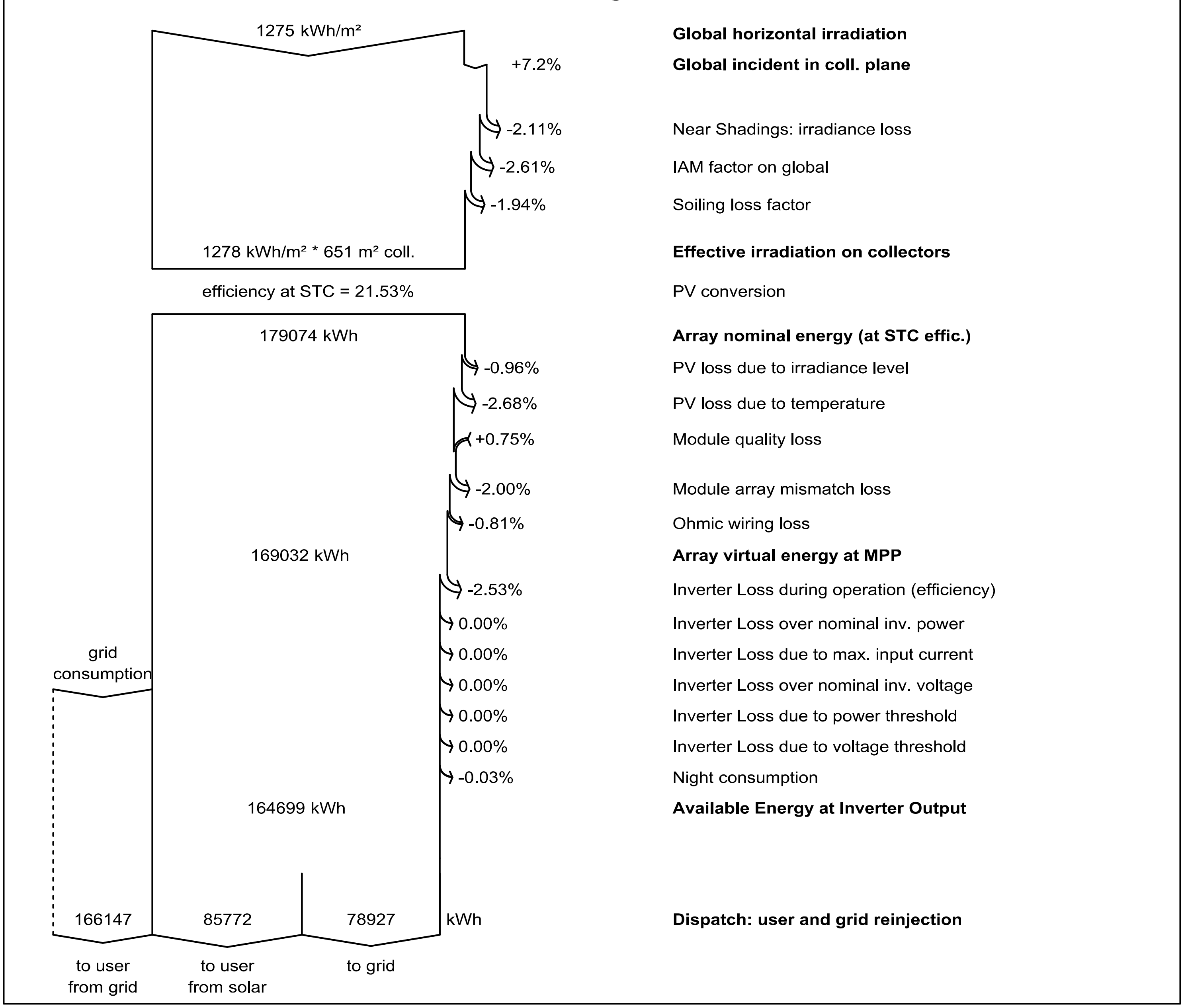
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Project: 995 Highway 215:Brooklyn Fire Station and Civic Centre

Variant: Brooklyn Fire Station and Civic Centre w/ground netmetering 140 kWp roof

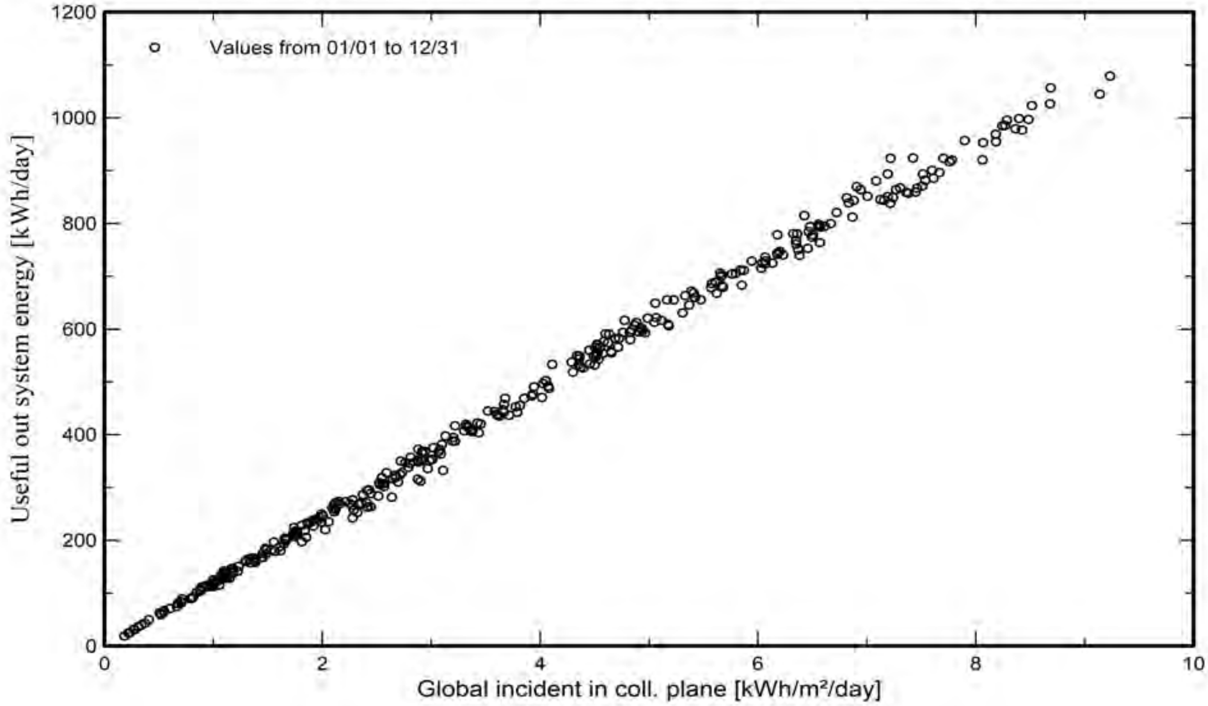
CBCL Limited (Canada)

Loss diagram

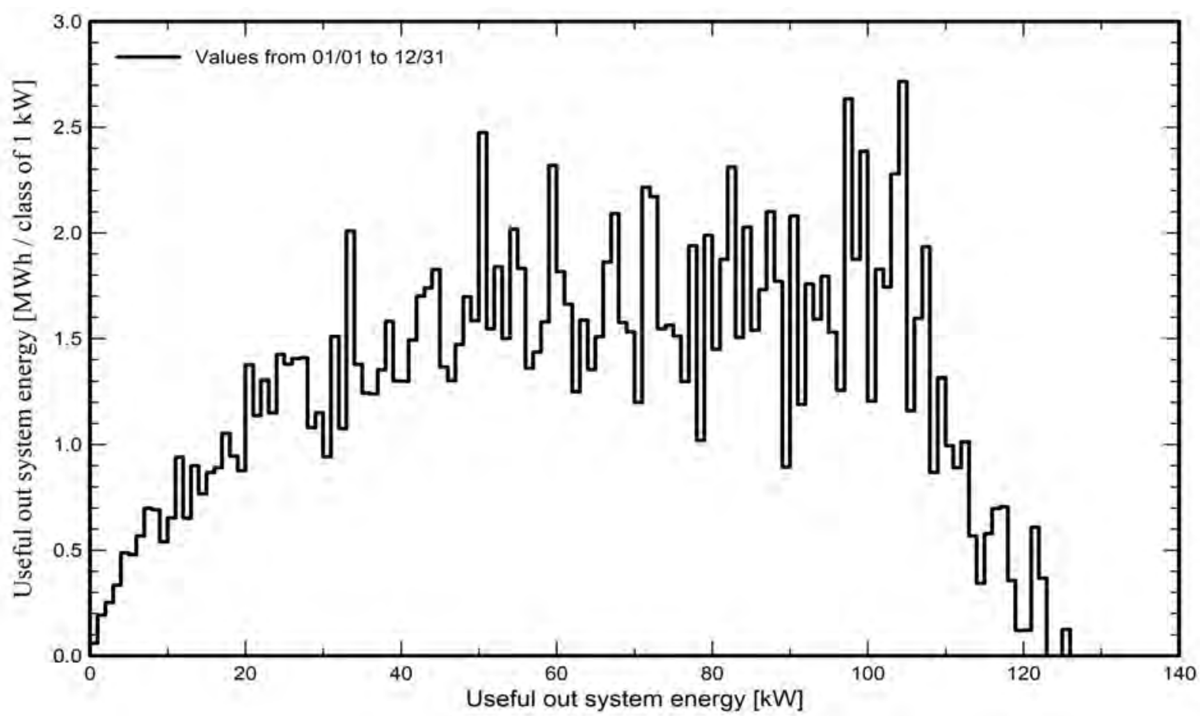


Predef. graphs

Daily Input/Output diagram

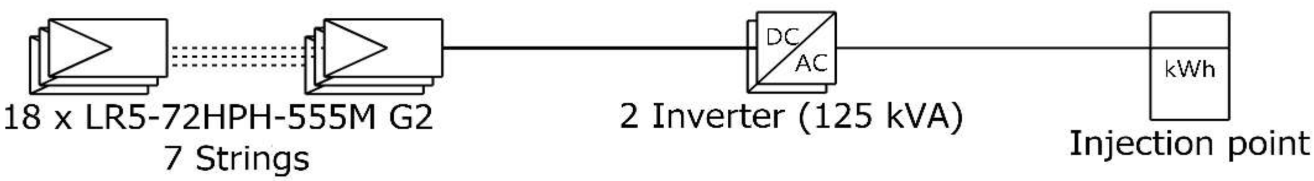


System Output Power Distribution



PVsyst V7.4.8
VC7, Simulation date:
08/15/24 12:09
with V7.4.8

Single-line diagram



PV module	LR5-72HPH-555M G2
Inverter	Sunny Tripower STP62-US-41-Core1
String	18 x LR5-72HPH-555M G2

Brooklyn Fire Station and Civic Centre	CBCL Limited (Canada)
VC7 : Brooklyn Fire Station and Civic Centre w/ground netmetering 140 kWp	08/15/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 995 Highway 215:Brooklyn Fire Station and Civic Centre

Variant: Brooklyn Fire Station and Civic Centre 506kWp w/ground netmetering FULL ground MOnofacial

Sheds on ground

System power: 506 kWp

Brooklyn Nova Scotia - Canada

Author

CBCL Limited (Canada)

Project: 995 Highway 215:Brooklyn Fire Station and Civic Centre

Variant: Brooklyn Fire Station and Civic Centre 506kWp w/ground netmetering FULL ground MOnofacial

CBCL Limited (Canada)

Project summary

Geographical Site
Brooklyn Nova Scotia
Canada

Situation

Latitude	45.00 °N
Longitude	-64.01 °W
Altitude	17 m
Time zone	UTC-4

Project settings

Albedo	0.20

Weather data
Brooklyn Nova Scotia
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System

Sheds on ground

PV Field Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

System information

PV Array		Inverters	
Nb. of modules	912 units	Nb. of units	7 units
Pnom total	506 kWp	Pnom total	438 kWac
		Pnom ratio	1.157

Results summary

Produced Energy	652243 kWh/year	Specific production	1289 kWh/kWp/year	Perf. Ratio PR	87.23 %
Used Energy	251919 kWh/year			Solar Fraction SF	41.83 %

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General parameters

Grid-Connected System

Sheds on ground

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Sheds configuration
Nb. of sheds 92 units
Sizes
Sheds spacing 11.0 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 41.6 %
Shading limit angle
Limit profile angle 21.4 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
22.0	22.6	20.4	14.7	13.1	11.9	27.8	35.5	26.6	20.0	17.1	20.3	252	MWh/mth

PV Array Characteristics

PV module
Manufacturer Longi Solar
Model LR5-72HPH-555M G2
(Original PVsyst database)
Unit Nom. Power 555 Wp
Number of PV modules 912 units
Nominal (STC) 506 kWp
Modules 57 string x 16 In series
At operating cond. (50°C)
Pmpp 464 kWp
U mpp 605 V
I mpp 766 A

Inverter
Manufacturer SMA
Model Sunny Tripower STP62-US-41-Core1
(Original PVsyst database)
Unit Nom. Power 62.5 kWac
Number of inverters 7 units
Total power 438 kWac
Operating voltage 150-800 V
Pnom ratio (DC:AC) 1.16
Power sharing within this inverter

Total PV power
Nominal (STC) 506 kWp
Total 912 modules
Module area 2356 m²
Cell area 2187 m²

Total inverter power
Total power 438 kWac
Number of inverters 7 units
Pnom ratio 1.16

Array losses

Array Soiling Losses
Average loss Fraction 1.8 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	4.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	0.0%	3.0%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 13 mΩ
Loss Fraction 1.5 % at STC

Module Quality Loss
Loss Fraction -0.8 %

Module mismatch losses
Loss Fraction 2.0 % at MPP

Array losses

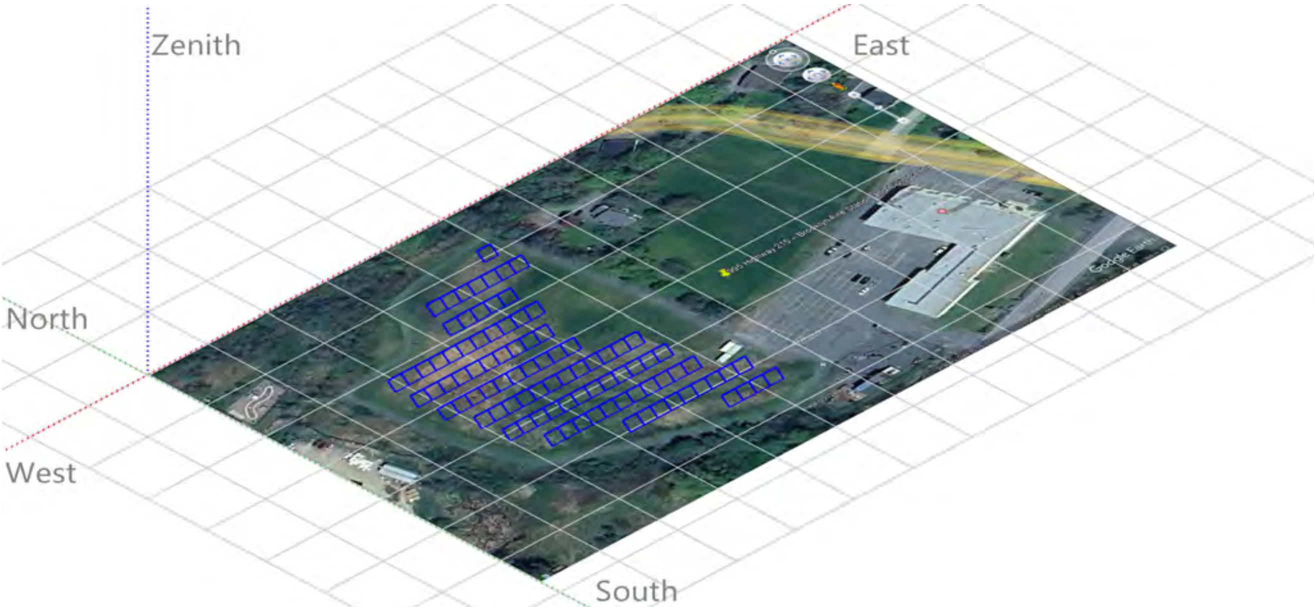
IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

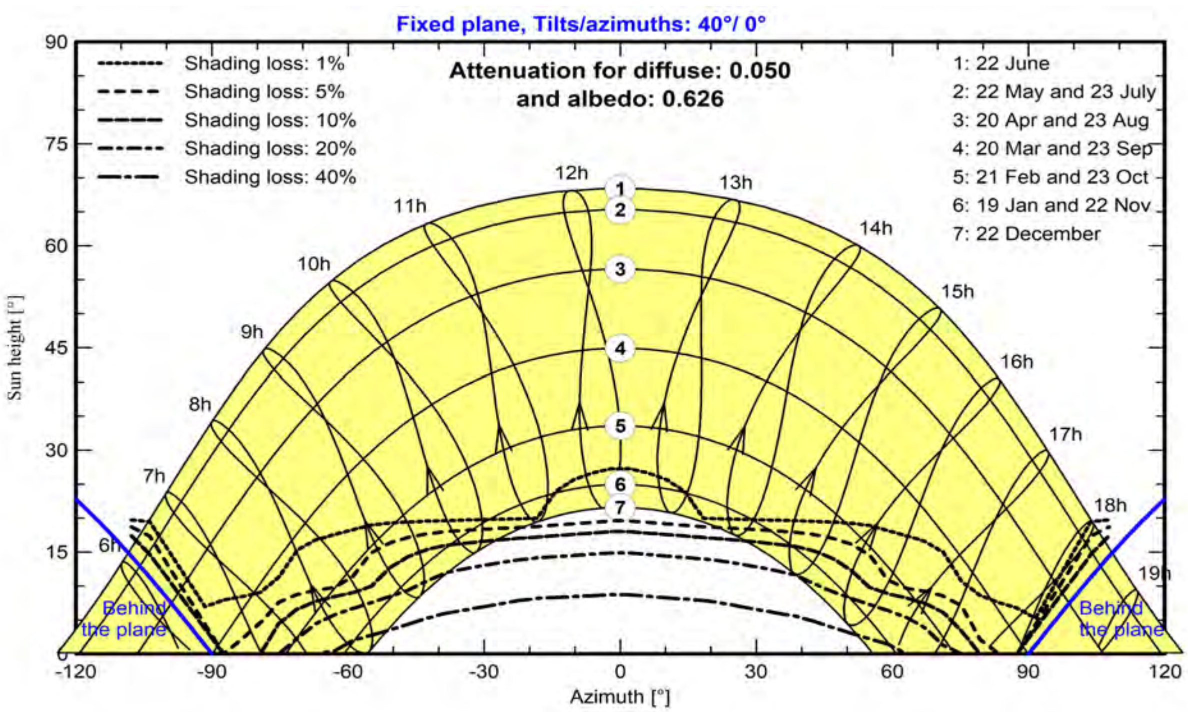
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

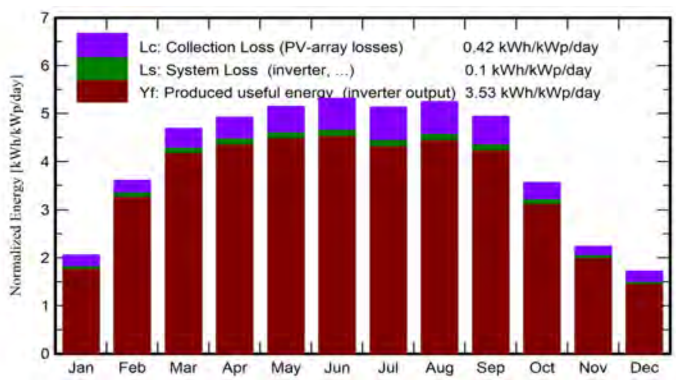


Main results

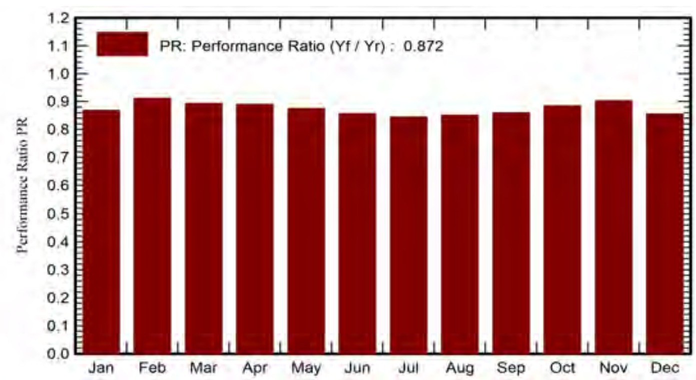
System Production

Produced Energy	652243 kWh/year	Specific production	1289 kWh/kWp/year
Used Energy	251919 kWh/year	Perf. Ratio PR	87.23 %
		Solar Fraction SF	41.83 %

Normalized productions (per installed kWp)



Performance Ratio PR



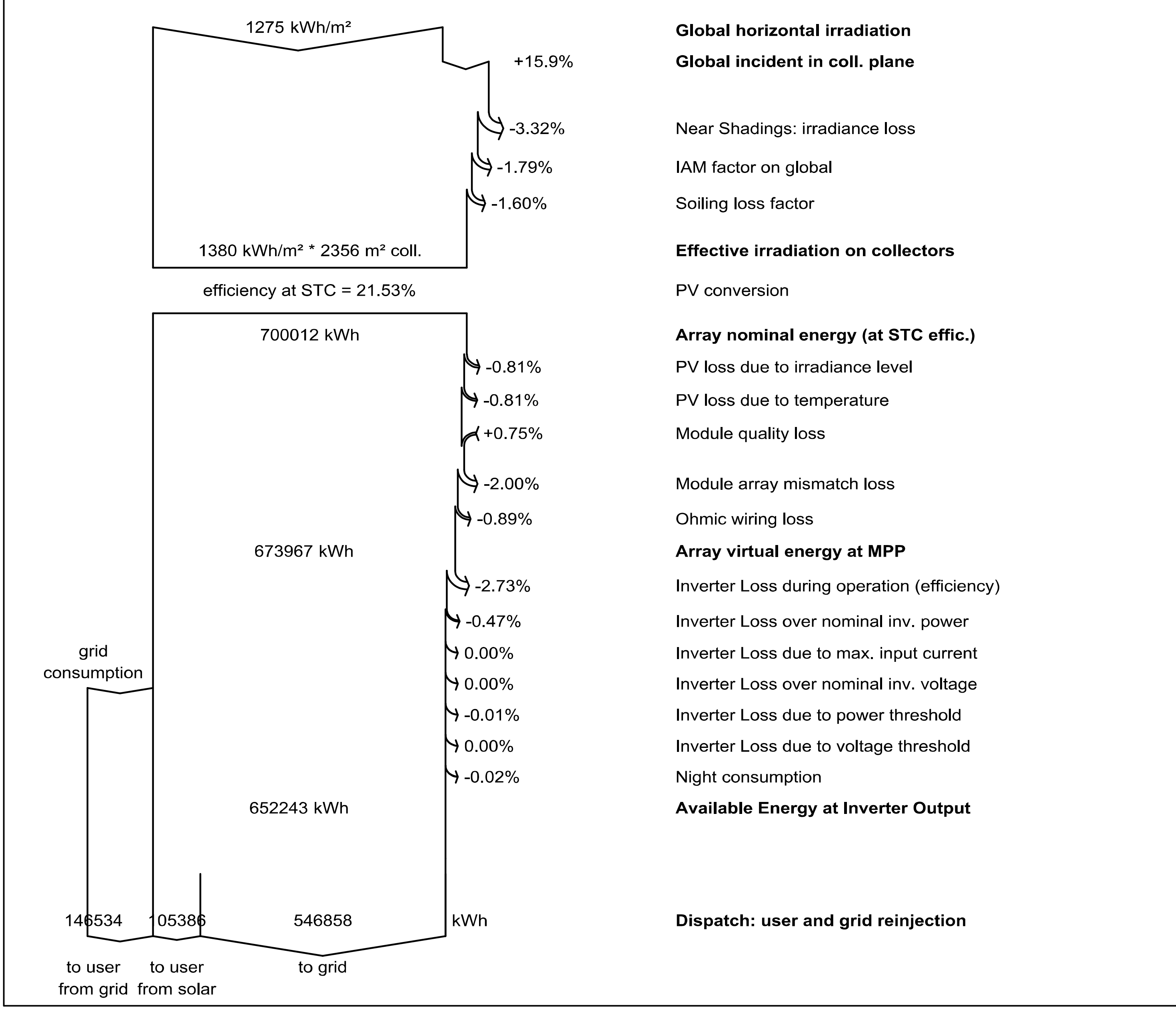
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.1	21.94	-5.11	63.8	55.7	28892	22020	6179	21886	15841
February	64.4	30.86	-4.76	100.8	92.9	47772	22584	8154	38349	14430
March	108.6	42.74	-0.99	145.4	135.8	67581	20442	8706	57053	11735
April	133.7	63.40	4.64	147.6	139.4	68296	14672	7254	59184	7417
May	165.9	88.99	10.49	159.5	149.2	72598	13068	7220	63406	5848
June	173.4	73.92	15.48	159.5	149.7	71115	11851	6798	62298	5053
July	168.8	83.06	20.38	159.2	149.3	70065	27787	14340	53747	13447
August	155.4	72.79	19.84	162.6	153.4	72055	35543	16745	53298	18797
September	120.0	47.57	15.65	148.3	140.8	66415	26585	11841	52707	14744
October	76.6	36.39	9.64	110.2	104.6	50736	19968	7724	41593	12244
November	41.0	24.47	3.95	67.1	62.7	31538	17097	5157	25498	11940
December	29.8	18.40	-1.29	53.3	46.5	23800	20304	5266	17837	15039
Year	1274.8	604.54	7.40	1477.3	1380.3	670864	251919	105386	546858	146534

Legends

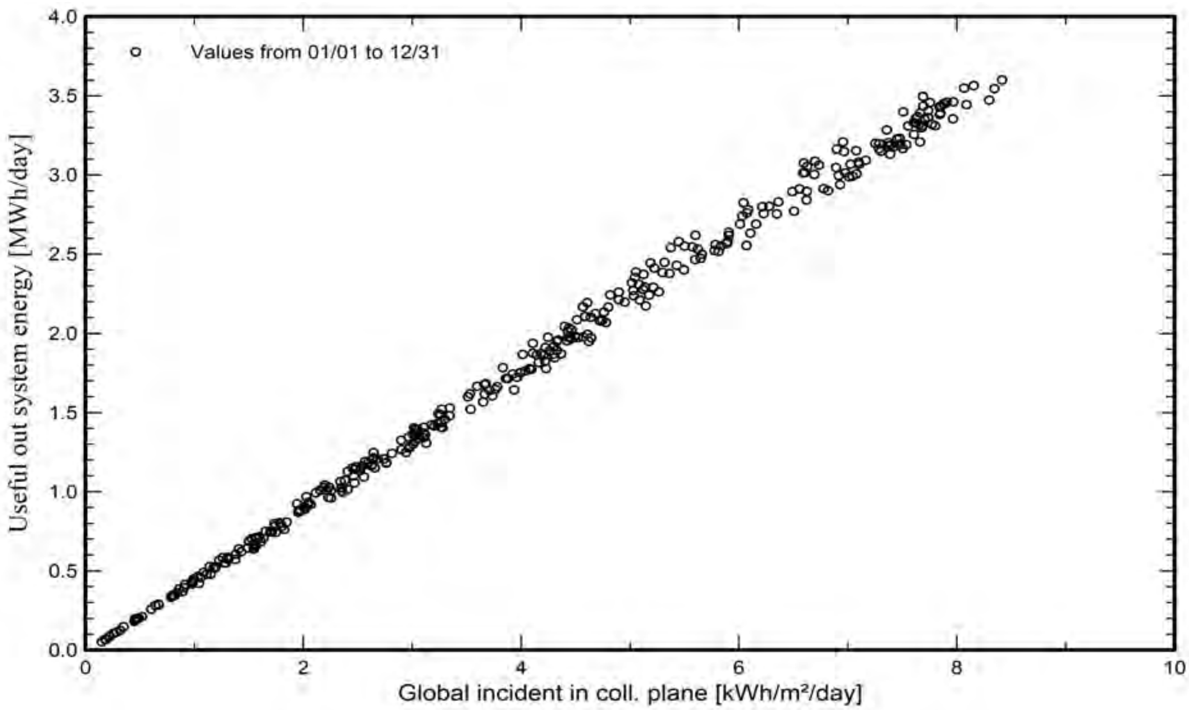
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

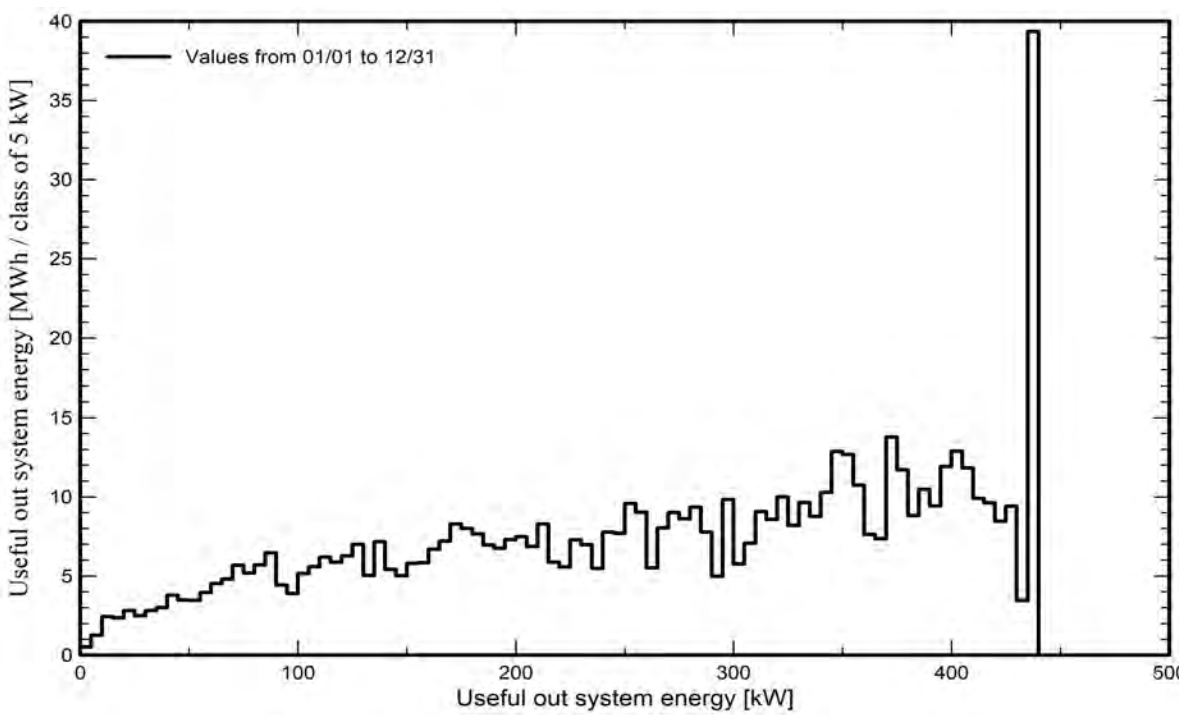


Predef. graphs

Daily Input/Output diagram

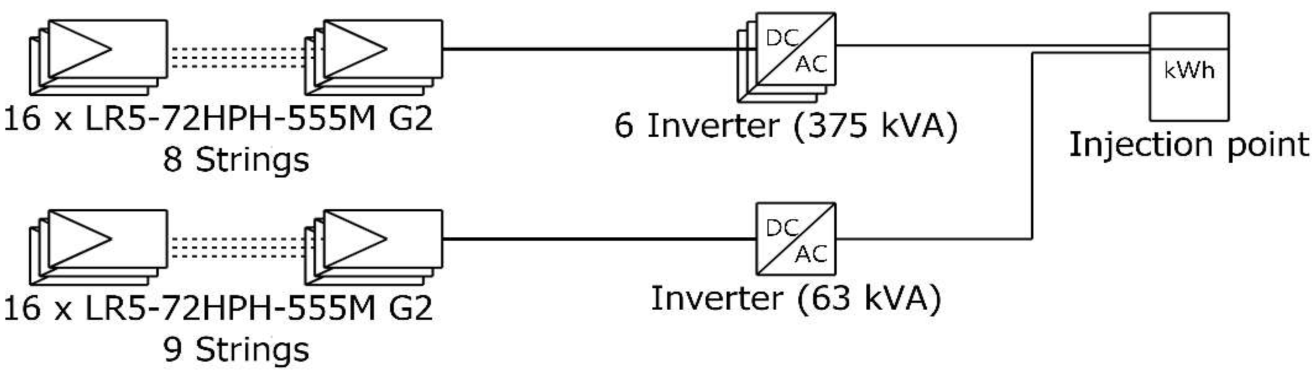


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC9, Simulation date:
08/15/24 12:03
with V7.4.8



PV module	LR5-72HPH-555M G2
Inverter	Sunny Tripower STP62-US-41-Core1
String	16 x LR5-72HPH-555M G2

Brooklyn Fire Station and Civic C entre	CBCL Limited (Can ada)
VC9 : Brooklyn Fire Station and Civic C entre 506kWp w/ground netmetering F	08/15/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 995 Highway 215:Brooklyn Fire Station and Civic Centre

Variant: Brooklyn Fire Station and Civic Centre 502kWp w/ground netmetering FULL ground bifacial

Sheds on ground

System power: 502 kWp

Brooklyn Nova Scotia - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site	Situation		Project settings	
Brooklyn Nova Scotia	Latitude	45.00 °N	Albedo	0.20
Canada	Longitude	-64.01 °W		
	Altitude	17 m		
	Time zone	UTC-4		

Weather data
Brooklyn Nova Scotia
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System — **Sheds on ground**

PV Field Orientation		Near Shadings	User's needs
Fixed plane		Linear shadings : Fast (table)	Monthly values
Tilt/Azimuth	40 / 0 °		

System information

PV Array		Inverters	
Nb. of modules	912 units	Nb. of units	7 units
Pnom total	502 kWp	Pnom total	438 kWac
		Pnom ratio	1.147

Results summary

Produced Energy	696262 kWh/year	Specific production	1388 kWh/kWp/year	Perf. Ratio PR	93.96 %
Used Energy	251919 kWh/year			Solar Fraction SF	42.75 %

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General parameters

Grid-Connected System | **Sheds on ground**

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Sheds configuration
Nb. of sheds 92 units
Sizes
Sheds spacing 11.0 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 41.6 %
Shading limit angle
Limit profile angle 21.4 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Bifacial system

Model 2D Calculation
unlimited sheds

Bifacial model geometry
Sheds spacing 11.00 m
Sheds width 4.58 m
Limit profile angle 21.4 °
GCR 41.6 %
Height above ground 1.50 m

Bifacial model definitions
Ground albedo 0.30
Bifaciality factor 70 %
Rear shading factor 5.0 %
Rear mismatch loss 10.0 %
Shed transparent fraction 0.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
22.0	22.6	20.4	14.7	13.1	11.9	27.8	35.5	26.6	20.0	17.1	20.3	252	MWh/mth

PV Array Characteristics

PV module

Manufacturer Longi Solar
Model LR5-72HBD-550M G2 Bifacial
(Original PVsyst database)
Unit Nom. Power 550 Wp
Number of PV modules 912 units
Nominal (STC) 502 kWp
Modules 57 string x 16 In series
At operating cond. (50°C)
Pmpp 460 kWp
U mpp 604 V
I mpp 760 A

Inverter

Manufacturer SMA
Model Sunny Tripower STP62-US-41-Core1
(Original PVsyst database)
Unit Nom. Power 62.5 kWac
Number of inverters 7 units
Total power 438 kWac
Operating voltage 150-800 V
Pnom ratio (DC:AC) 1.15
Power sharing within this inverter

Total PV power

Nominal (STC) 502 kWp
Total 912 modules
Module area 2356 m²
Cell area 2187 m²

Total inverter power

Total power 438 kWac
Number of inverters 7 units
Pnom ratio 1.15

Array losses

Array Soiling Losses

Average loss Fraction 1.9 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	4.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%

Thermal Loss factor

Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses

Global array res. 13 mΩ
Loss Fraction 1.5 % at STC

Module Quality Loss

Loss Fraction -0.8 %

Module mismatch losses

Loss Fraction 2.0 % at MPP

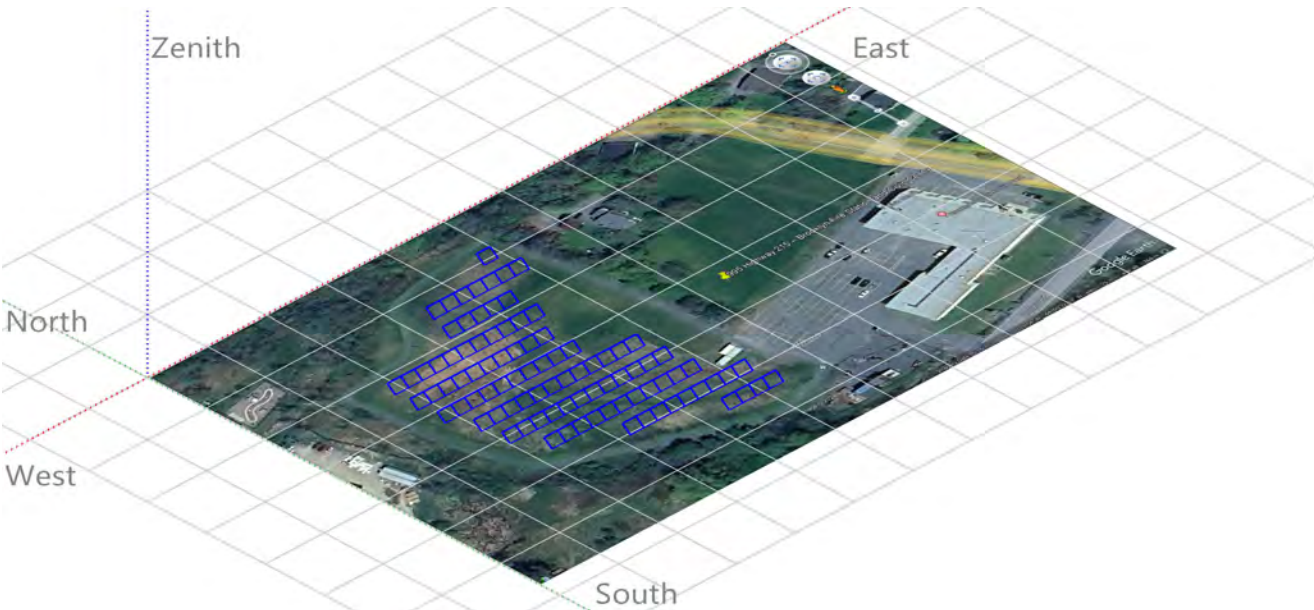
IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

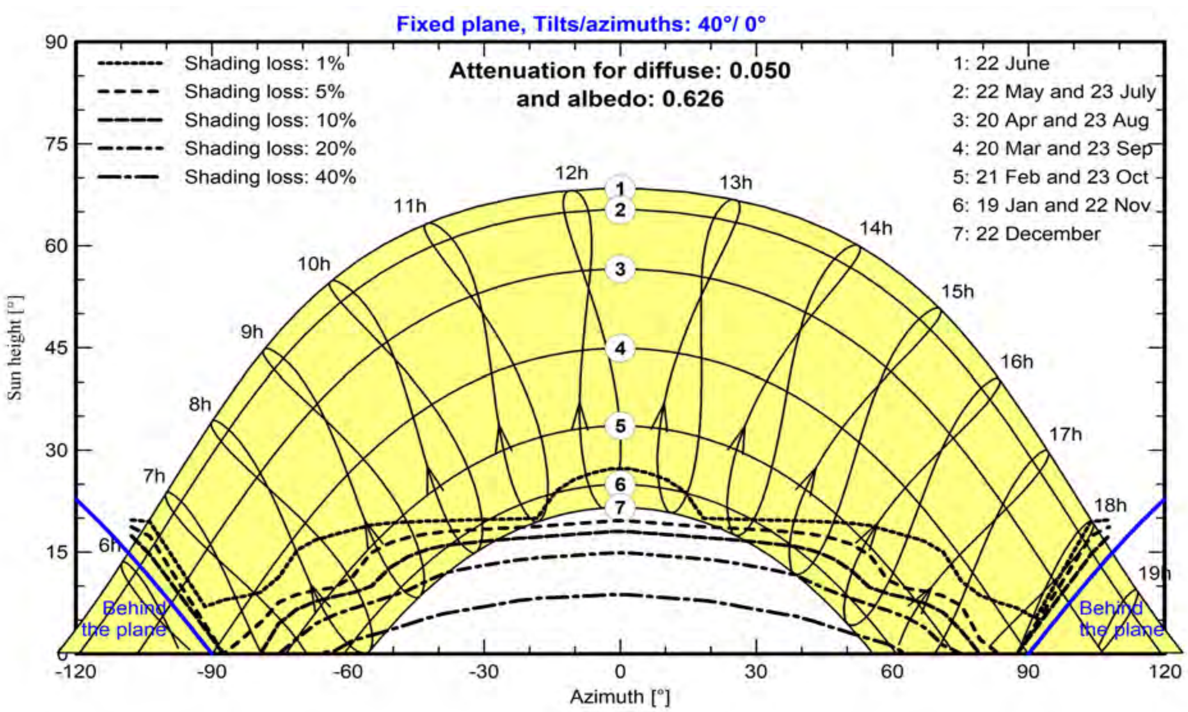
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

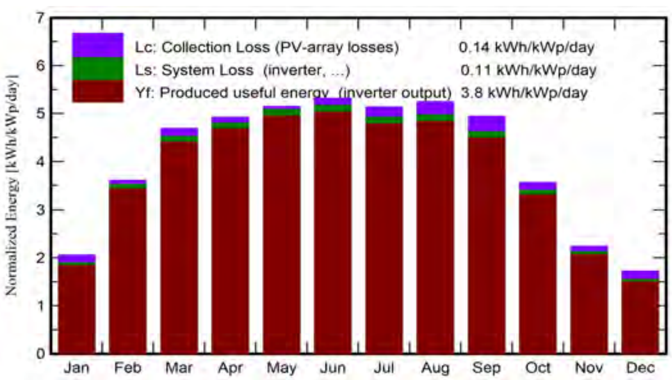


Main results

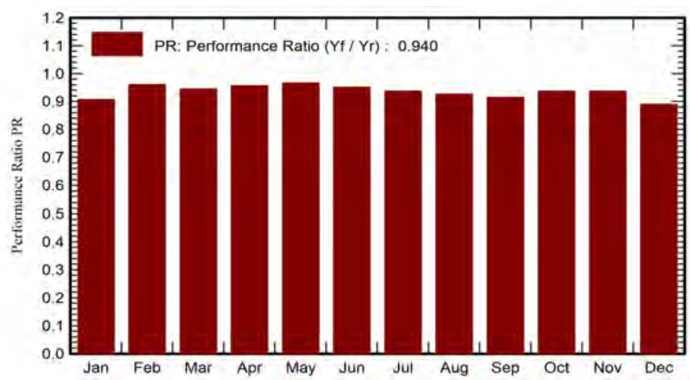
System Production

Produced Energy	696262 kWh/year	Specific production	1388 kWh/kWp/year
Used Energy	251919 kWh/year	Perf. Ratio PR	93.96 %
		Solar Fraction SF	42.75 %

Normalized productions (per installed kWp)



Performance Ratio PR



Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.1	21.94	-5.11	63.8	56.0	29894	22020	6323	22726	15697
February	64.4	30.86	-4.76	100.8	93.4	49910	22584	8228	40357	14356
March	108.6	42.74	-0.99	145.4	136.7	70786	20442	8792	60094	11650
April	133.7	63.40	4.64	147.6	140.8	72754	14672	7341	63447	7330
May	165.9	88.99	10.49	159.5	151.3	79501	13068	7382	69970	5686
June	173.4	73.92	15.48	159.5	151.9	78291	11851	6973	69106	4878
July	168.8	83.06	20.38	159.2	151.5	77014	27787	15056	59791	12731
August	155.4	72.79	19.84	162.6	155.2	77760	35543	17173	58407	18370
September	120.0	47.57	15.65	148.3	141.9	69945	26585	11967	56015	14617
October	76.6	36.39	9.64	110.2	105.2	53262	19968	7816	43963	12152
November	41.0	24.47	3.95	67.1	62.4	32421	17097	5246	26274	11851
December	29.8	18.40	-1.29	53.3	46.7	24525	20304	5402	18413	14902
Year	1274.8	604.54	7.40	1477.3	1392.8	716064	251919	107699	588562	144220

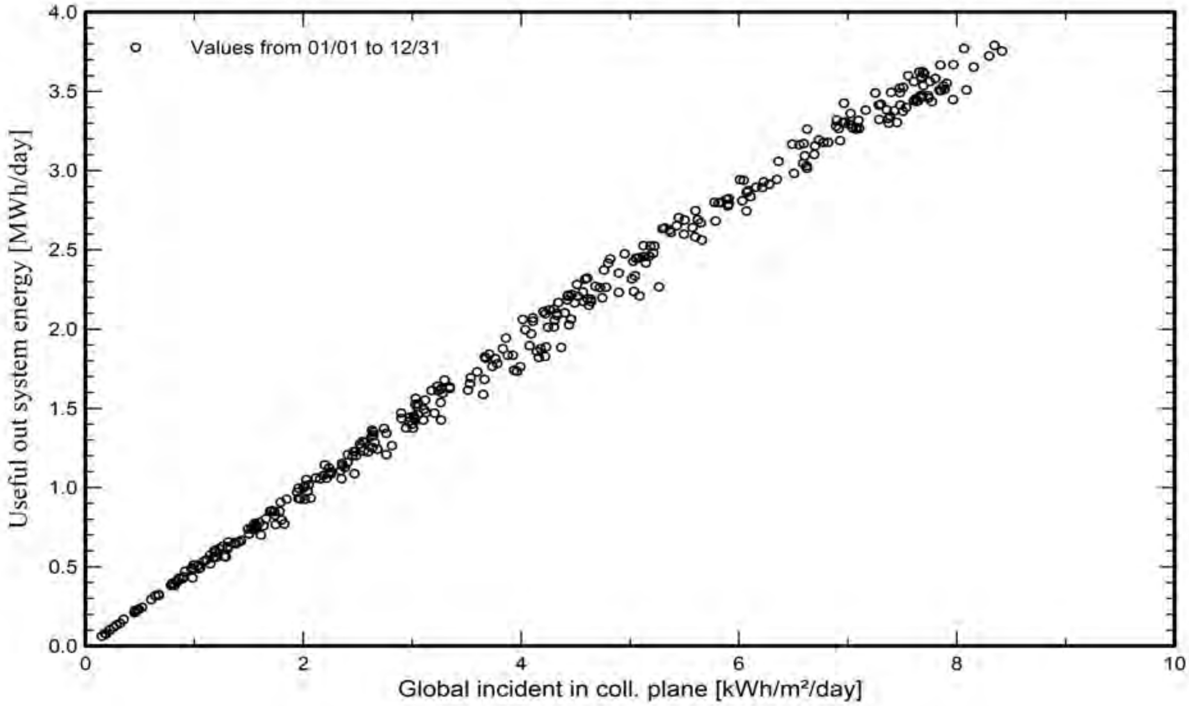
Legends

GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

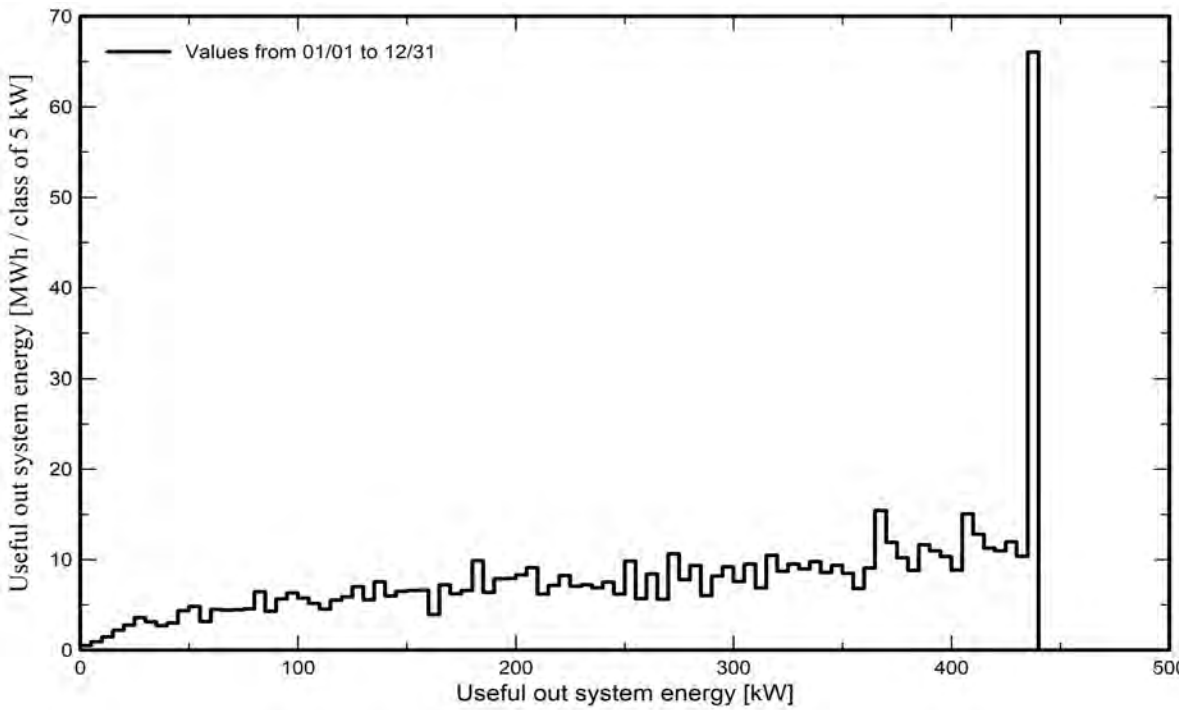
Loss diagram

Predef. graphs

Daily Input/Output diagram

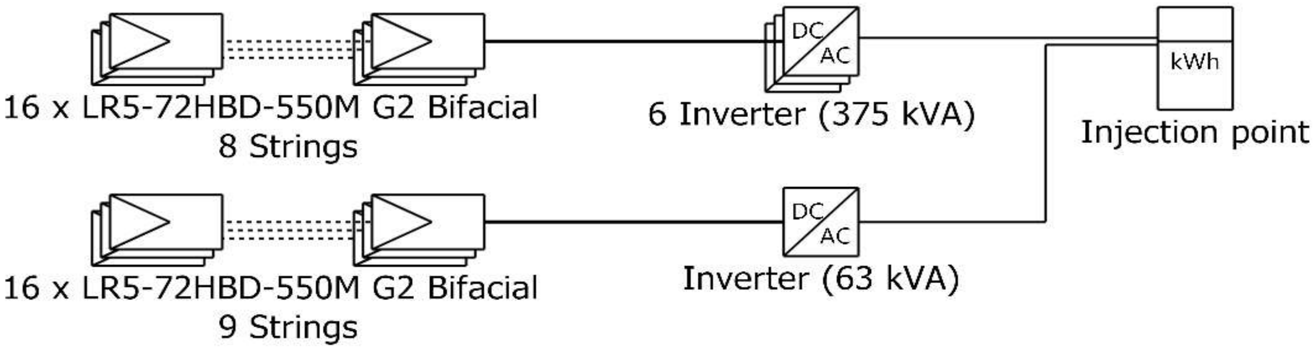


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC8, Simulation date:
08/15/24 12:06
with V7.4.8



PV module	LR5-72HBD-550M G2 Bifacial
Inverter	Sunny Tripower STP62-US-41-Core1
String	16 x LR5-72HBD-550M G2 Bifacial

Brooklyn Fire Station and Civic C entre	CBCL Limited (Can ada)
VC8 : Brooklyn Fire Station and Civic C entre 502kWp w/ground netmetering F	08/15/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 293 Wentworth Rd-Windsor Wastewater Treatment Lagoons

Variant: Windsor Wastewater Treatment Lagoons Ground Mono 330 kW
Sheds on ground
System power: 330 kWp
293 Wentworth Road Windsor NS - Canada

Author
CBCL Limited (Canada)

Project: 293 Wentworth Rd-Windsor Wastewater Treatment Lagoons

Variant: Windsor Wastewater Treatment Lagoons Ground Mono 330 kW

CBCL Limited (Canada)

Project summary

Geographical Site	Situation		Project settings	
293 Wentworth Road Windsor NS	Latitude	45.00 °N	Albedo	0.20
Canada	Longitude	-64.12 °W		
	Altitude	8 m		
	Time zone	UTC-4		

Weather data
293 Wentworth Road Windsor NS
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System — **Sheds on ground**

PV Field Orientation		Near Shadings	User's needs
Fixed plane		Linear shadings : Fast (table)	Monthly values
Tilt/Azimuth	40 / 0 °		

System information

PV Array		Inverters	
Nb. of modules	594 units	Nb. of units	6 units
Pnom total	330 kWp	Pnom total	300 kWac
		Pnom ratio	1.099

Results summary

Produced Energy	422869 kWh/year	Specific production	1283 kWh/kWp/year	Perf. Ratio PR	88.24 %
Used Energy	683728 kWh/year			Solar Fraction SF	33.40 %

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General parameters

Grid-Connected System

Sheds on ground

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Sheds configuration
Nb. of sheds 91 units
Sizes
Sheds spacing 10.5 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 43.6 %
Shading limit angle
Limit profile angle 22.8 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
49.0	62.3	69.1	59.9	51.8	57.8	48.2	54.4	55.4	49.7	59.6	66.6	684	MWh/mth

PV Array Characteristics

PV module
Manufacturer Longi Solar
Model LR5-72HPH-555M G2
(Original PVsyst database)
Unit Nom. Power 555 Wp
Number of PV modules 594 units
Nominal (STC) 330 kWp
Modules 33 string x 18 In series
At operating cond. (50°C)
Pmpp 302 kWp
U mpp 681 V
I mpp 444 A

Inverter
Manufacturer SMA
Model Sunny Tripower STP50-US-41-Core1
(Original PVsyst database)
Unit Nom. Power 50.0 kWac
Number of inverters 6 units
Total power 300 kWac
Operating voltage 150-800 V
Pnom ratio (DC:AC) 1.10
Power sharing within this inverter

Total PV power
Nominal (STC) 330 kWp
Total 594 modules
Module area 1534 m²
Cell area 1424 m²

Total inverter power
Total power 300 kWac
Number of inverters 6 units
Pnom ratio 1.10

Array losses

Array Soiling Losses
Average loss Fraction 1.9 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	4.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 25 mΩ
Loss Fraction 1.5 % at STC

Module Quality Loss
Loss Fraction -0.8 %

Module mismatch losses
Loss Fraction 2.0 % at MPP

Array losses

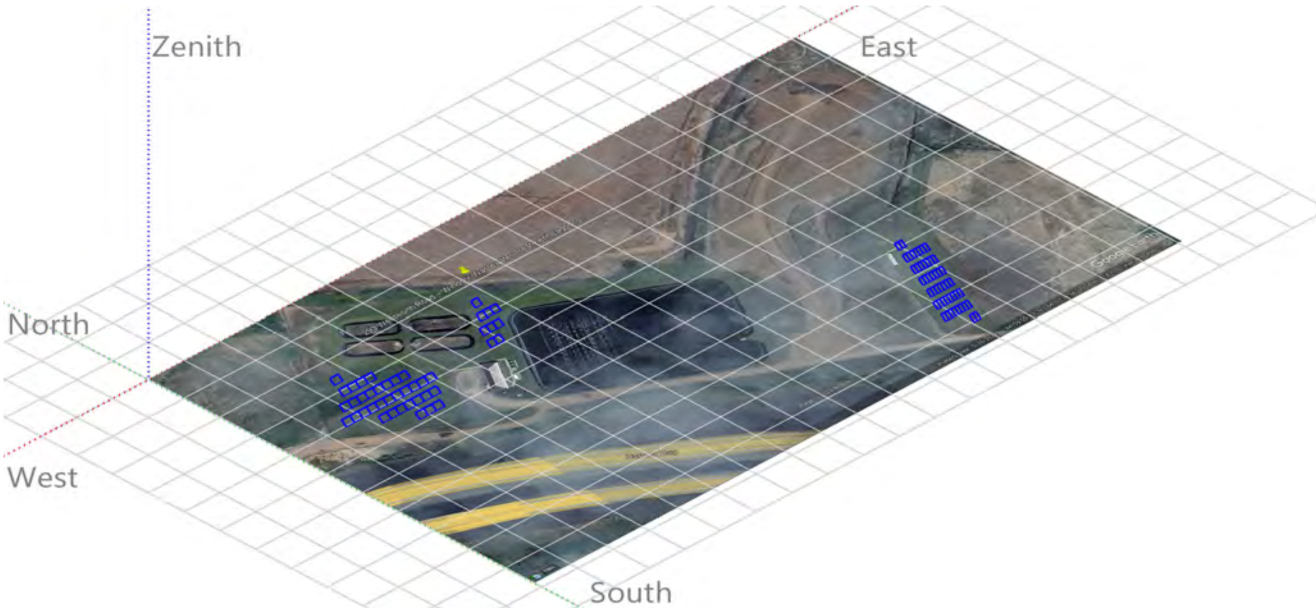
IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

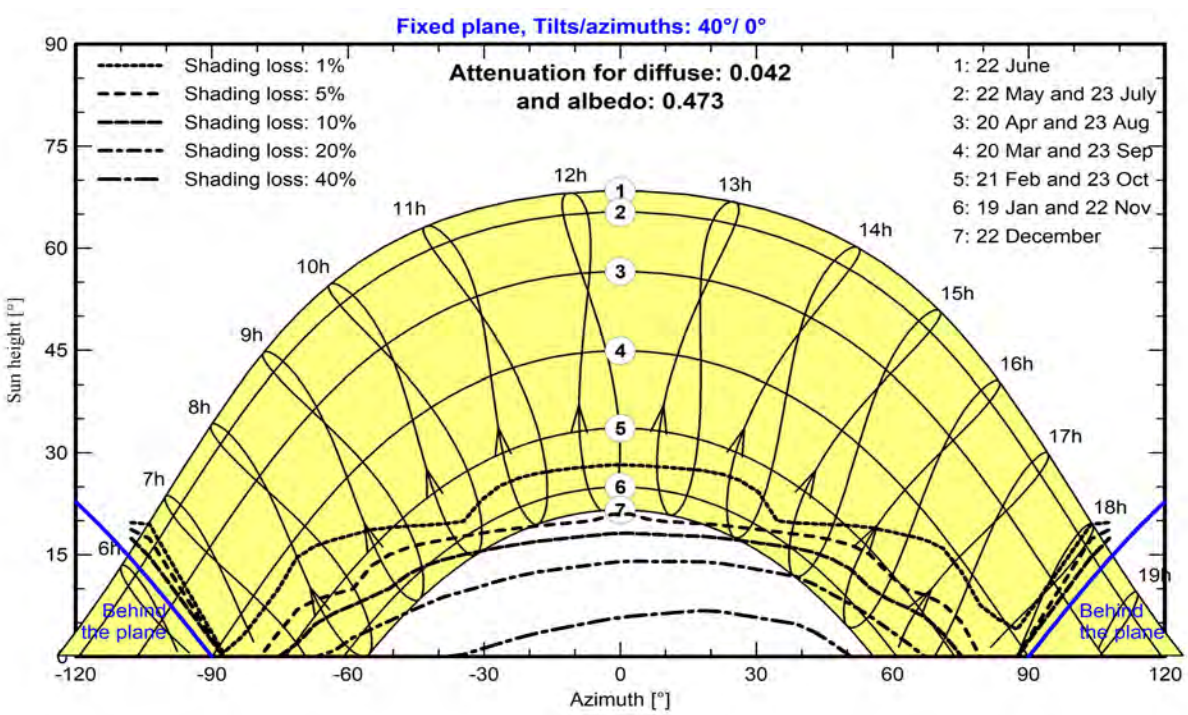
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

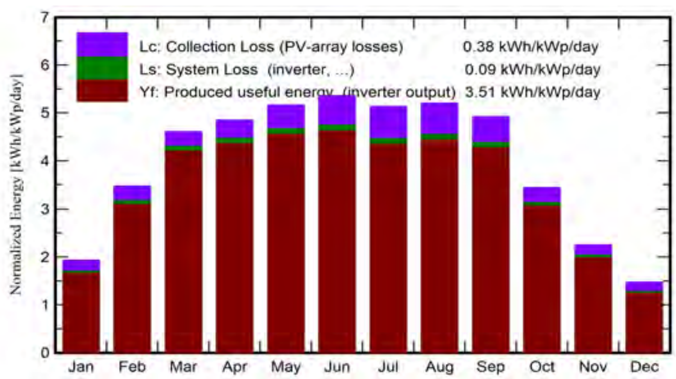


Main results

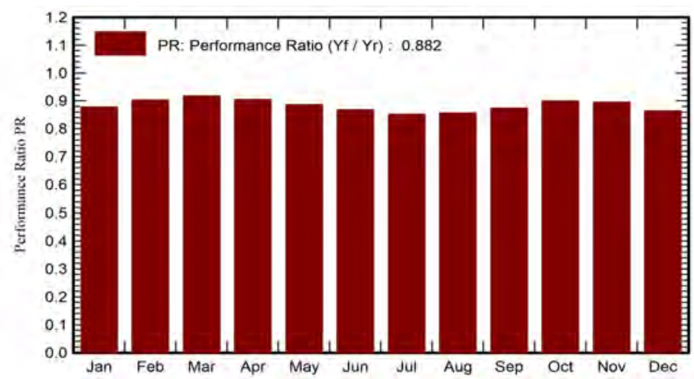
System Production

Produced Energy	422869 kWh/year	Specific production	1283 kWh/kWp/year
Used Energy	683728 kWh/year	Perf. Ratio PR	88.24 %
		Solar Fraction SF	33.40 %

Normalized productions (per installed kWp)



Performance Ratio PR



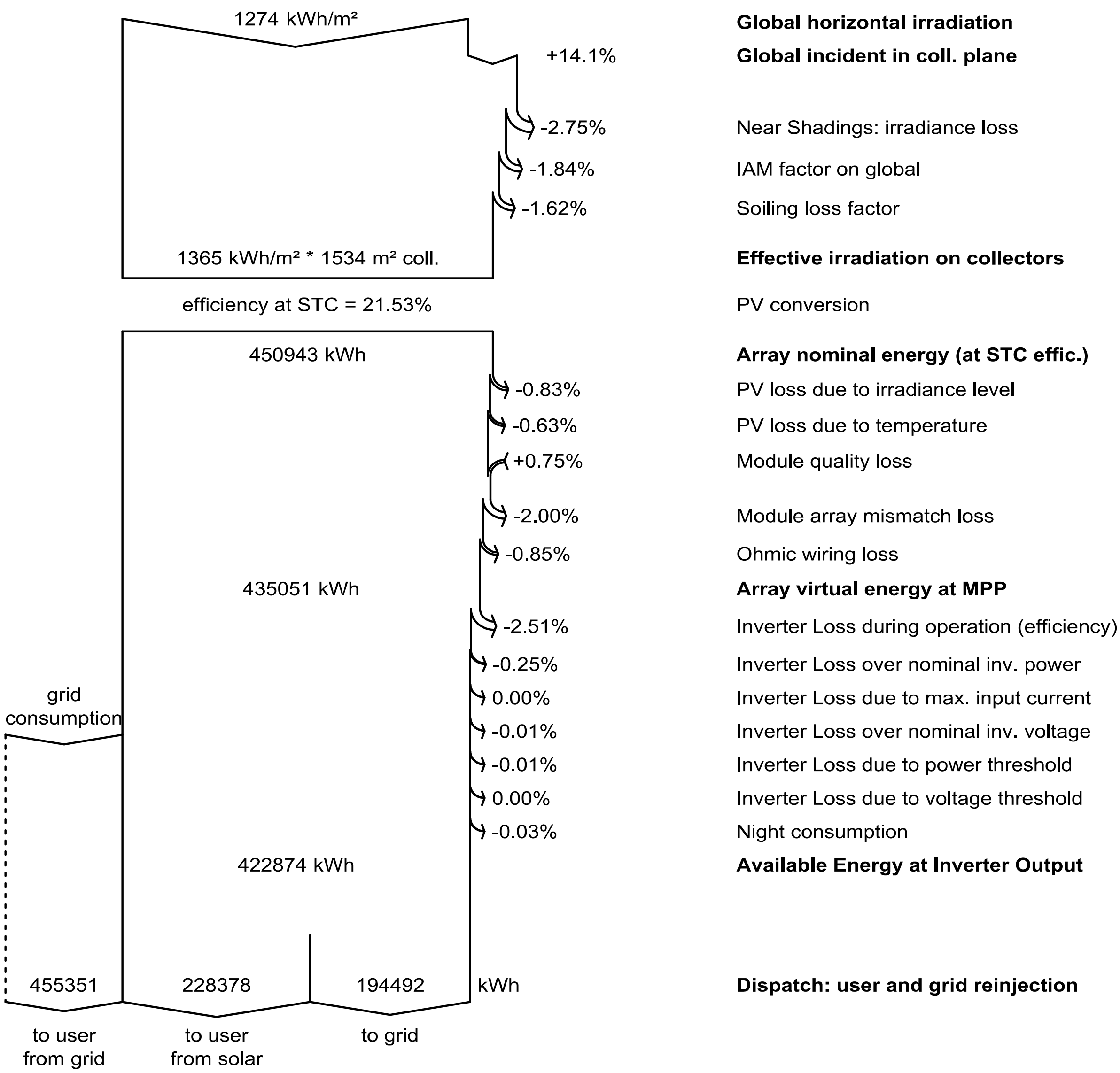
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.2	24.69	-4.94	59.8	52.5	17748	48960	10714	6584	38245
February	64.4	32.10	-4.62	97.1	89.9	29594	62271	17996	10910	44275
March	108.5	52.41	-0.87	142.9	133.8	44268	69129	24290	18941	44839
April	133.1	70.22	4.96	145.5	137.9	44498	59940	23605	19792	36335
May	165.8	88.28	10.82	160.0	151.0	48026	51797	22502	24300	29295
June	173.5	83.51	15.80	160.8	151.8	47246	57820	24658	21336	33162
July	168.9	82.68	20.58	159.1	150.3	45919	48184	21147	23531	27037
August	155.4	75.63	20.04	161.3	153.1	46810	54412	22490	23081	31922
September	120.1	52.84	15.55	147.6	140.7	43651	55429	21182	21336	34247
October	76.6	44.92	9.64	106.6	101.4	32384	49667	16450	15130	33217
November	41.0	23.51	4.04	67.5	62.8	20455	59551	12343	7567	47208
December	29.7	22.56	-1.18	45.6	40.0	13353	66569	11001	1985	55568
Year	1274.2	653.35	7.56	1453.7	1365.2	433953	683728	228378	194492	455351

Legends

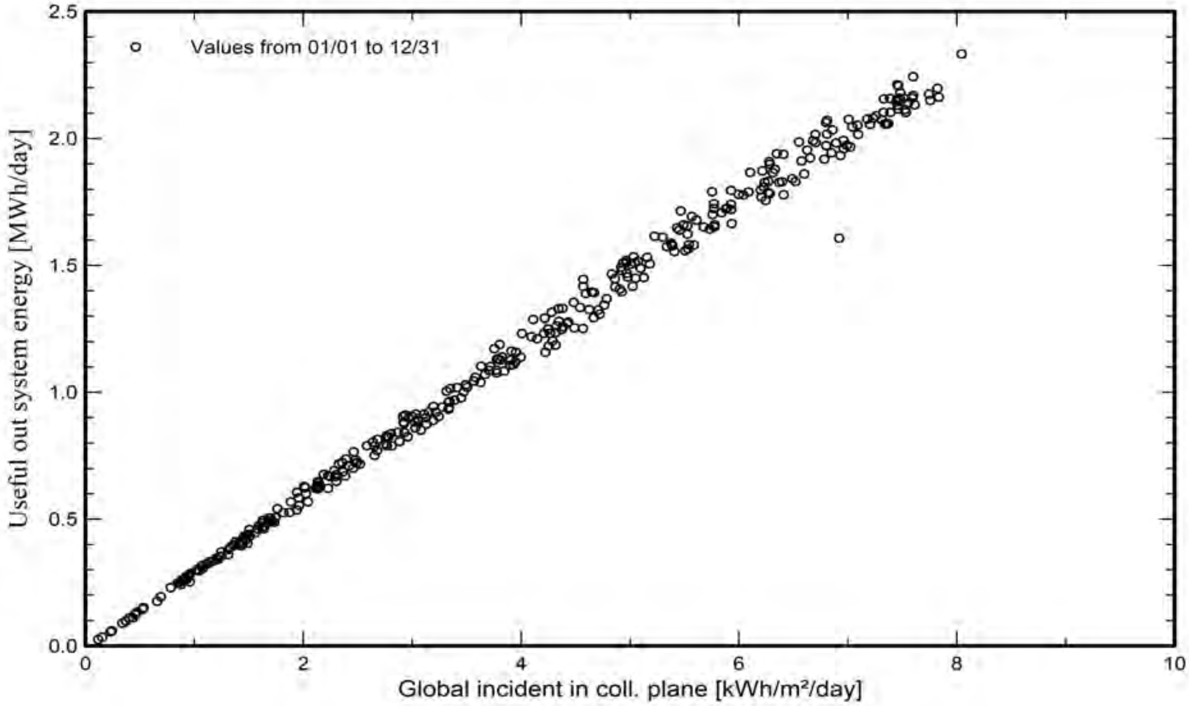
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

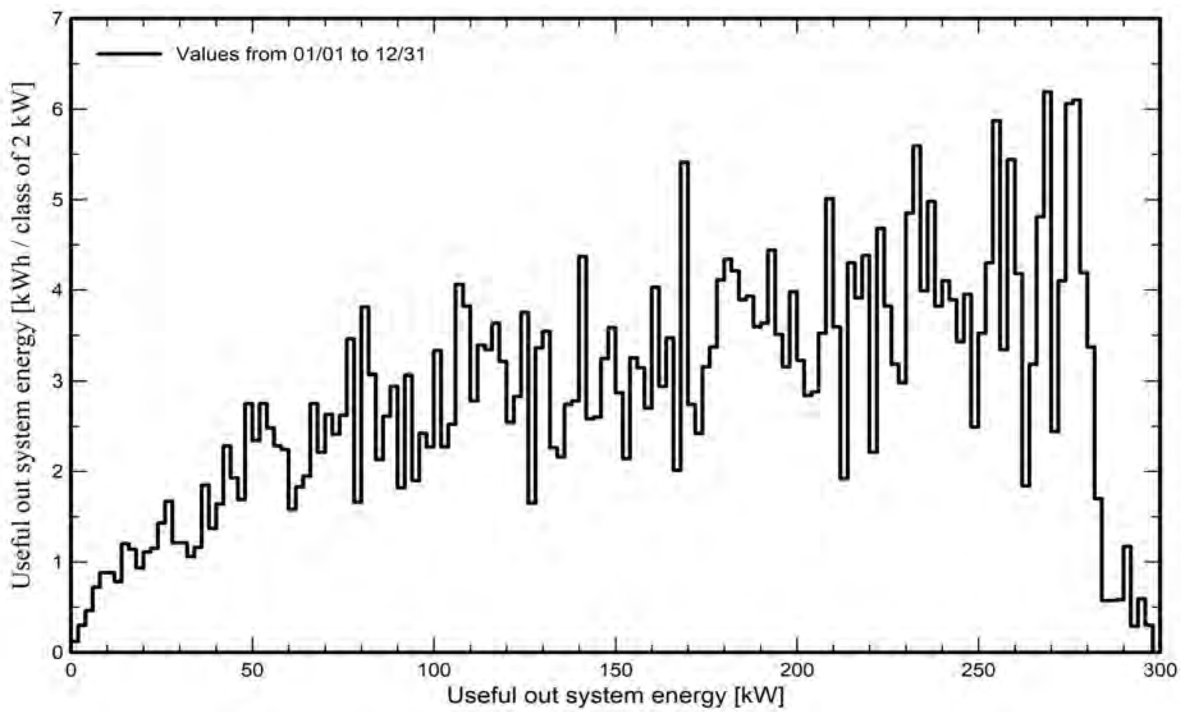


Predef. graphs

Daily Input/Output diagram

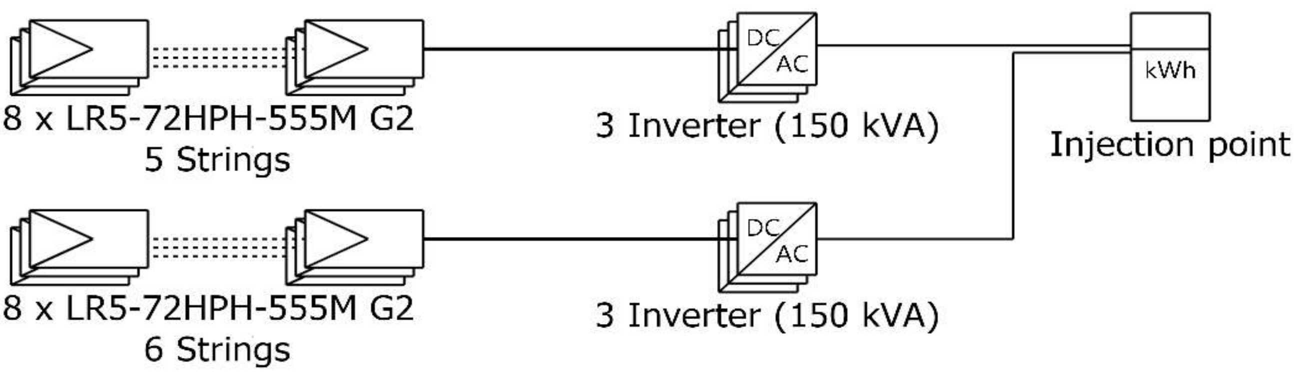


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC1, Simulation date:
08/18/24 13:58
with V7.4.8



PV module	LR5-72HPH-555M G2
Inverter	Sunny Tripower STP50-US-41-Core1
String	18 x LR5-72HPH-555M G2

293 Wentworth Rd-Windsor Wastewater Treatment Lagoons	CBCL Limited (Canada)
VC1 : Windsor Wastewater Treatment Lagoons Ground Mono 330 kW	09/11/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 293 Wentworth Rd-Windsor Wastewater Treatment Lagoons

Variant: Windsor Wastewater Treatment Lagoons Ground BIFACIAL 327 kW

Sheds on ground

System power: 327 kWp

293 Wentworth Road Windsor NS - Canada

Author

CBCL Limited (Canada)

Project: 293 Wentworth Rd-Windsor Wastewater Treatment Lagoons

Variant: Windsor Wastewater Treatment Lagoons Ground BIFACIAL 327 kW

CBCL Limited (Canada)

Project summary

Geographical Site
293 Wentworth Road Windsor NS
Canada

Situation

Latitude	45.00 °N
Longitude	-64.12 °W
Altitude	8 m
Time zone	UTC-4

Project settings

Albedo	0.20

Weather data
293 Wentworth Road Windsor NS
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System

Sheds on ground

PV Field Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

System information

PV Array

Nb. of modules	594 units
Pnom total	327 kWp

Inverters

Nb. of units	6 units
Pnom total	300 kWac
Pnom ratio	1.089

Results summary

Produced Energy	452185 kWh/year	Specific production	1384 kWh/kWp/year	Perf. Ratio PR	95.21 %
Used Energy	683729 kWh/year			Solar Fraction SF	34.54 %

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General parameters

Grid-Connected System

Sheds on ground

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Sheds configuration
Nb. of sheds 91 units

Sizes
Sheds spacing 10.5 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 43.6 %

Shading limit angle
Limit profile angle 22.8 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Bifacial system
Model 2D Calculation
unlimited sheds

Bifacial model geometry

Sheds spacing	10.50 m
Sheds width	4.58 m
Limit profile angle	22.8 °
GCR	43.6 %
Height above ground	1.50 m

Bifacial model definitions

Ground albedo	0.30
Bifaciality factor	70 %
Rear shading factor	5.0 %
Rear mismatch loss	10.0 %
Shed transparent fraction	0.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
49.0	62.3	69.1	59.9	51.8	57.8	48.2	54.4	55.4	49.7	59.6	66.6	684	MWh/mth

PV Array Characteristics

PV module

Manufacturer	Longi Solar
Model	LR5-72HBD-550M G2 Bifacial
(Original PVsyst database)	
Unit Nom. Power	550 Wp
Number of PV modules	594 units
Nominal (STC)	327 kWp
Modules	33 string x 18 In series
At operating cond. (50°C)	
Pmpp	299 kWp
U mpp	680 V
I mpp	440 A

Inverter

Manufacturer	SMA
Model	Sunny Tripower STP50-US-41-Core1
(Original PVsyst database)	
Unit Nom. Power	50.0 kWac
Number of inverters	6 units
Total power	300 kWac
Operating voltage	150-800 V
Pnom ratio (DC:AC)	1.09
Power sharing within this inverter	

Total PV power

Nominal (STC)	327 kWp
Total	594 modules
Module area	1534 m²
Cell area	1424 m²

Total inverter power

Total power	300 kWac
Number of inverters	6 units
Pnom ratio	1.09

Array losses

Array Soiling Losses

Average loss Fraction 1.9 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	4.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%

Thermal Loss factor

Module temperature according to irradiance

Uc (const) 29.0 W/m²K

Uv (wind) 0.0 W/m²K/m/s

DC wiring losses

Global array res. 26 mΩ

Loss Fraction 1.5 % at STC

Module Quality Loss

Loss Fraction -0.8 %

Module mismatch losses

Loss Fraction 2.0 % at MPP

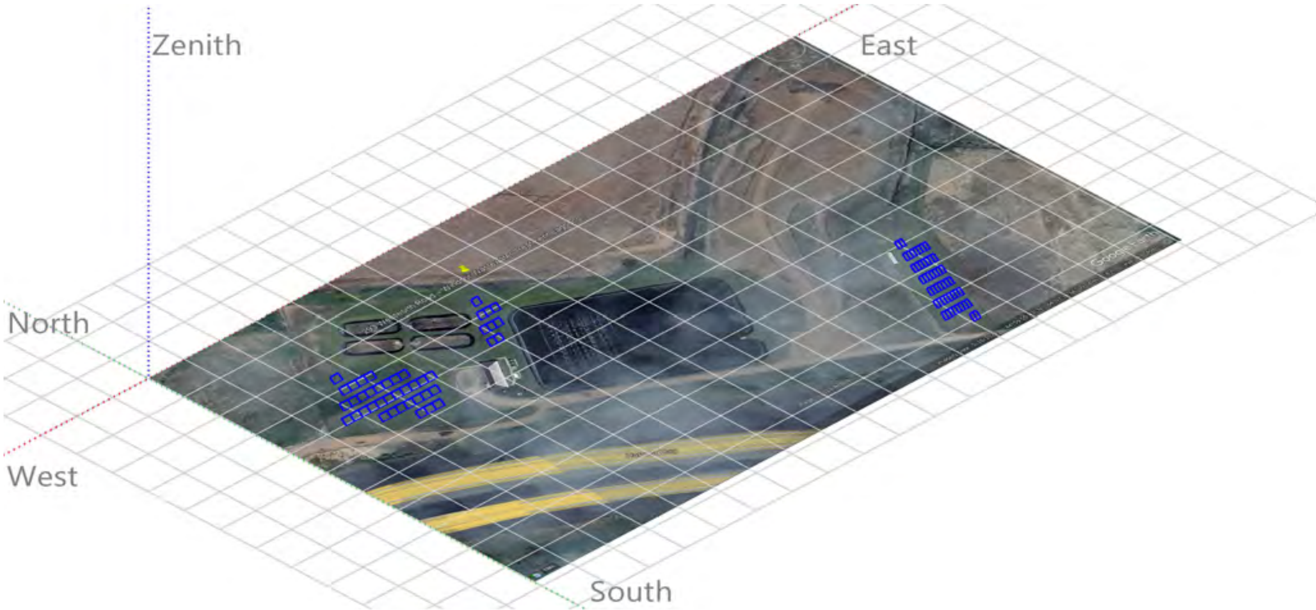
IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

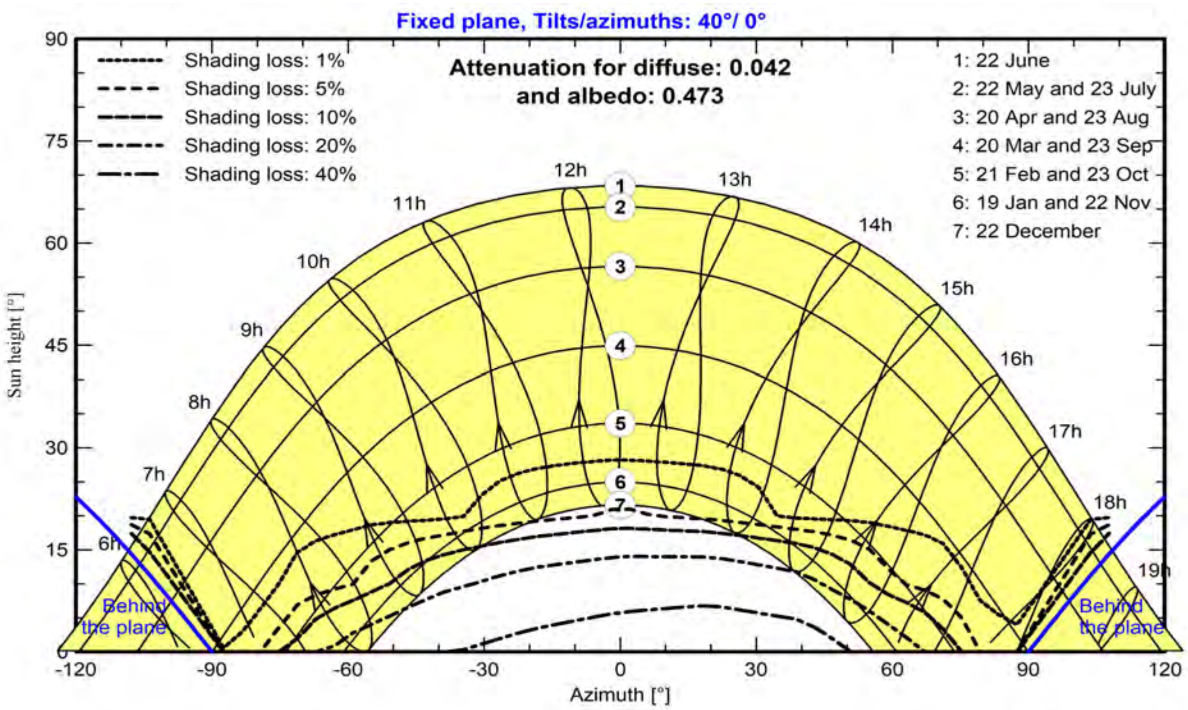
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

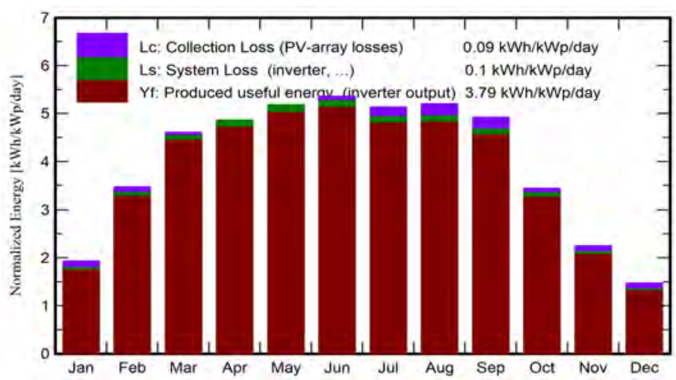


Main results

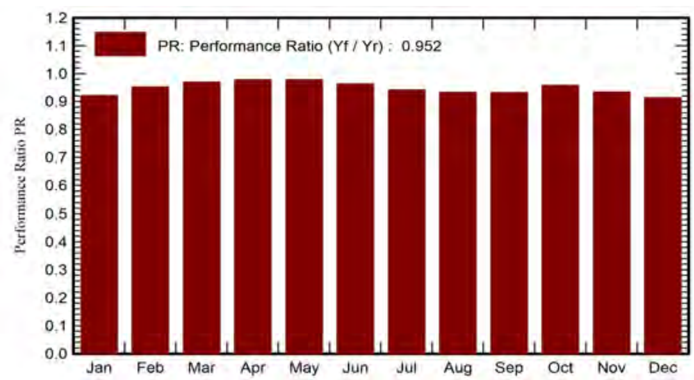
System Production

Produced Energy	452185 kWh/year	Specific production	1384 kWh/kWp/year
Used Energy	683729 kWh/year	Perf. Ratio PR	95.21 %
		Solar Fraction SF	34.54 %

Normalized productions (per installed kWp)



Performance Ratio PR



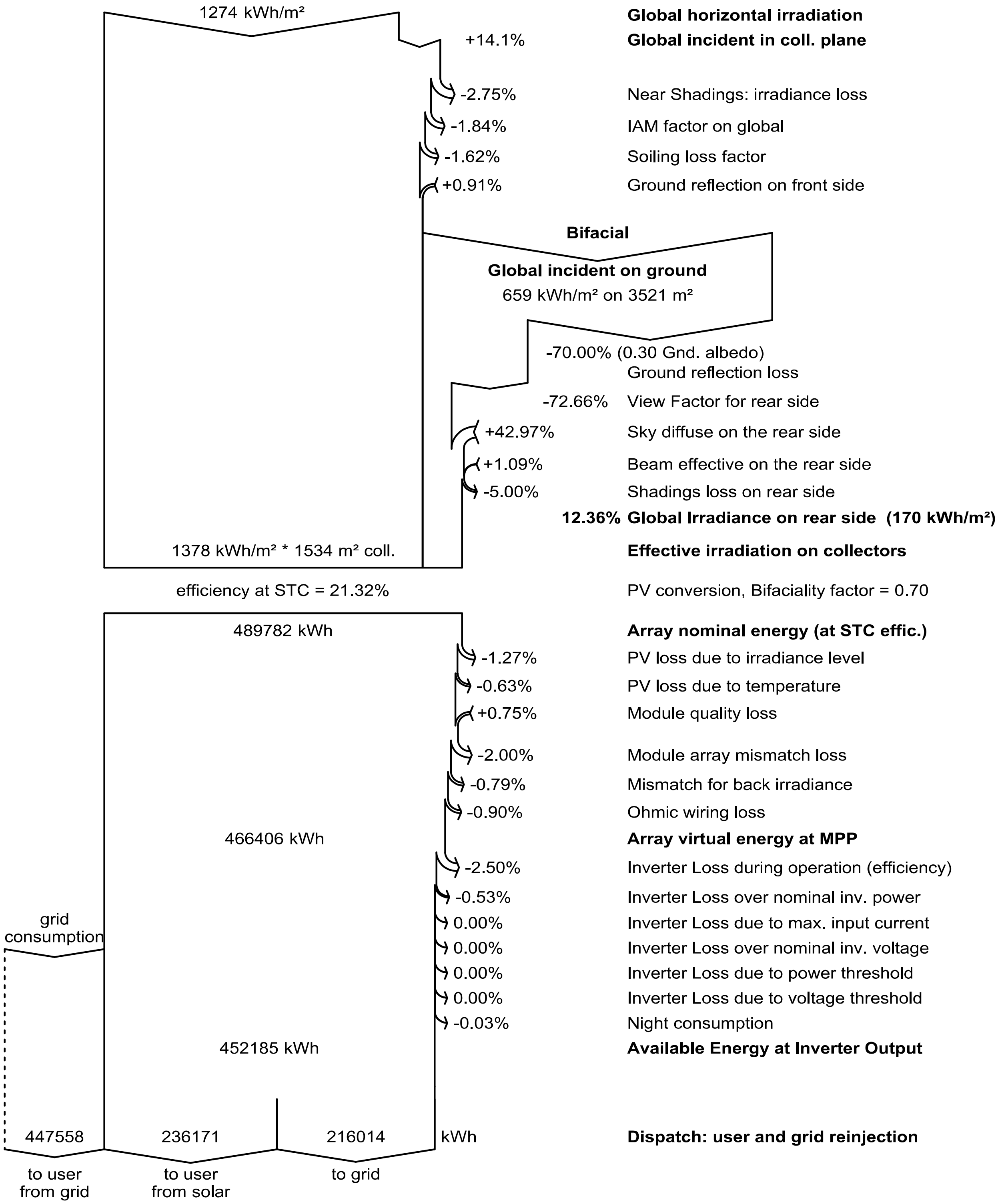
Balances and main results

	GlobHor	DiffHor	T_Amb	GlobInc	GlobEff	EArray	E_User	E_Solar	E_Grid	EFrGrid
	kWh/m²	kWh/m²	°C	kWh/m²	kWh/m²	kWh	kWh	kWh	kWh	kWh
January	37.2	24.69	-4.94	59.8	52.8	18456	48960	11059	6934	37901
February	64.4	32.10	-4.62	97.1	90.3	30922	62271	18451	11754	43820
March	108.5	52.41	-0.87	142.9	134.6	46357	69129	24743	20521	44386
April	133.1	70.22	4.96	145.5	139.2	47656	59940	24354	22123	35586
May	165.8	88.28	10.82	160.0	152.9	52484	51797	23492	27659	28305
June	173.5	83.51	15.80	160.8	153.9	51957	57820	25944	24646	31876
July	168.9	82.68	20.58	159.1	152.3	50277	48184	22179	26756	26005
August	155.4	75.63	20.04	161.3	154.7	50478	54412	23279	25867	31133
September	120.1	52.84	15.55	147.6	141.7	46116	55429	21665	23254	33764
October	76.6	44.92	9.64	106.6	101.9	34167	49667	16781	16535	32886
November	41.0	23.51	4.04	67.5	63.1	21143	59551	12688	7893	46863
December	29.7	22.56	-1.18	45.6	40.3	13988	66569	11538	2071	55031
Year	1274.2	653.35	7.56	1453.7	1377.6	464000	683729	236171	216014	447558

Legends

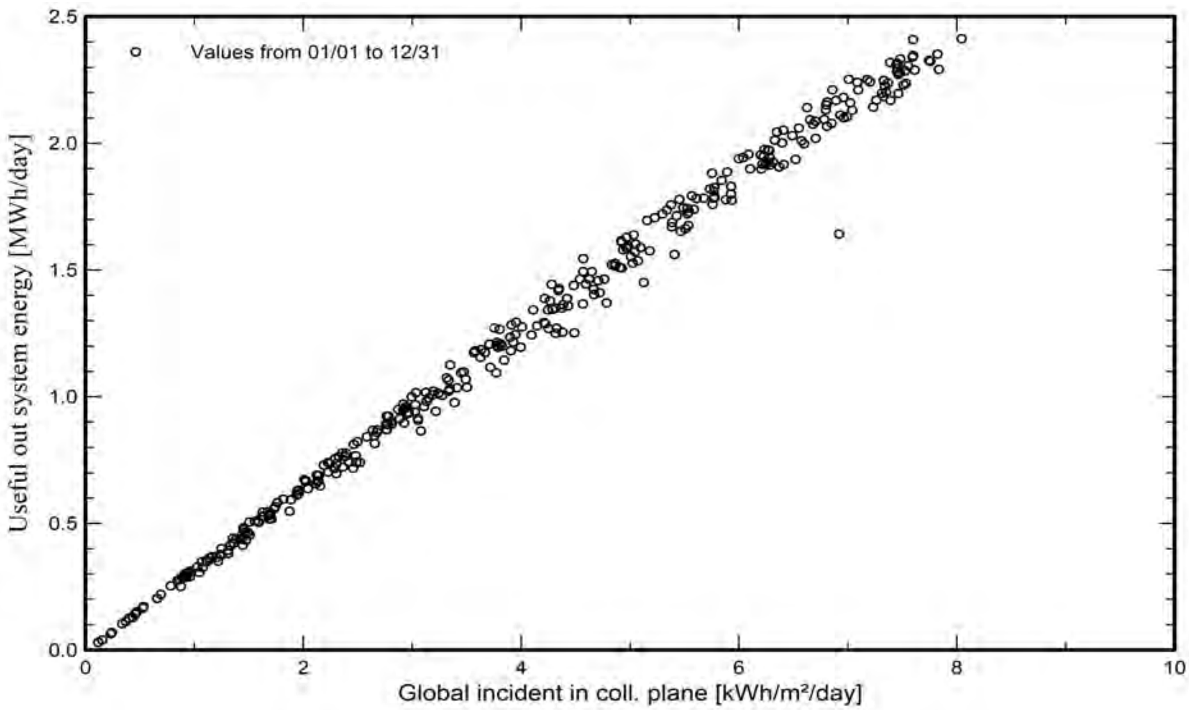
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

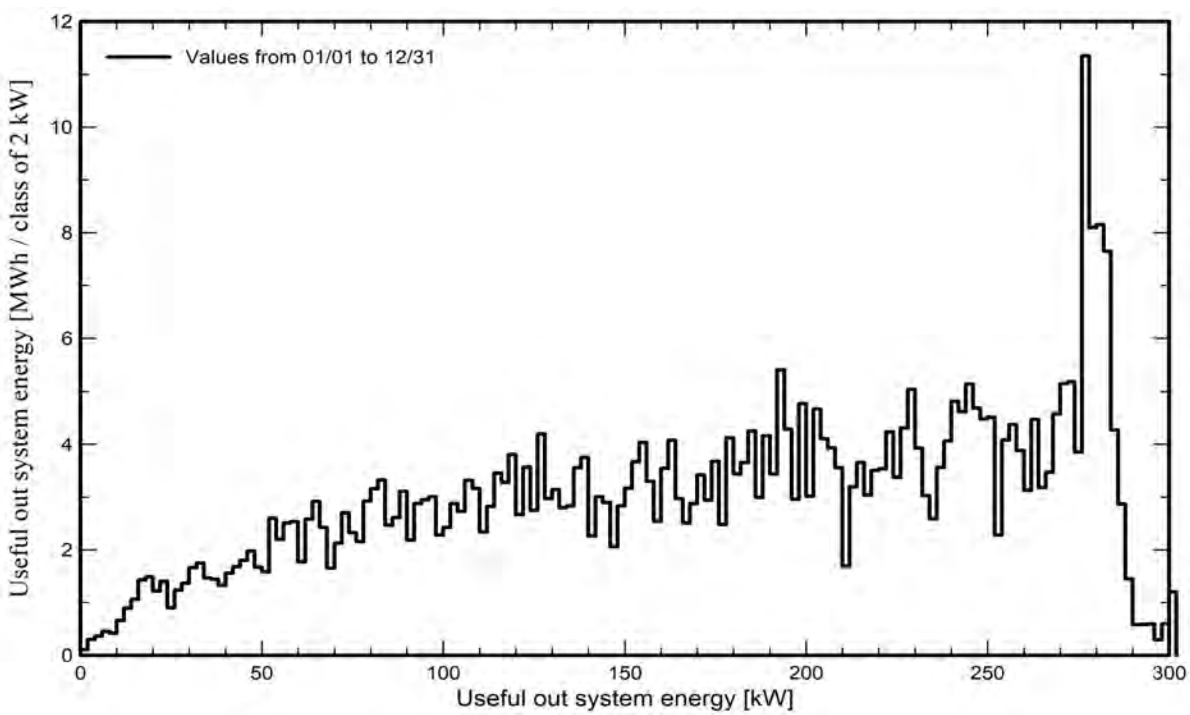


Predef. graphs

Daily Input/Output diagram

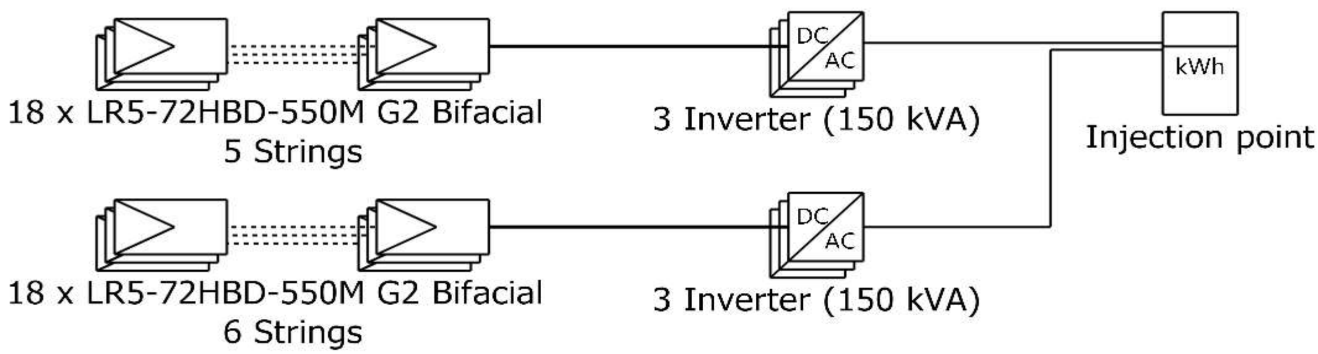


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC3, Simulation date:
09/05/24 10:48
with V7.4.8



PV module	LR5-72HBD-550M G2 Bifacial
Inverter	Sunny Tripower STP50-US-41-Core1
String	18 x LR5-72HBD-550M G2 Bifacial

293 Wentworth Rd-Windsor Wastewater Treatment Lagoons	CBCL Limited (Canada)
VC3 : Windsor Wastewater Treatment Lagoons Ground BIFACIAL 327 kW	09/05/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: Falmouth Wastewater Treatment Plant

Variant: Falmouth Wastewater Treatment Plant 28.9 Wp Roof MONO

Building system

System power: 28.86 kWp

48 Falmouth Connector Rd - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site		**Situation**		**Project settings**	
48 Falmouth Connector Rd		Latitude	45.00 °N	Albedo	0.20
Canada		Longitude	-64.16 °W		
		Altitude	13 m		
		Time zone	UTC-4		

Weather data
48 Falmouth Connector Rd
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System	**Building system**	
PV Field Orientation	**Near Shadings**	**User's needs**
Fixed plane	Linear shadings : Fast (table)	Monthly values
Tilt/Azimuth 30 / 18.4 °		

System information

PV Array		**Inverters**	
Nb. of modules	52 units	Nb. of units	2 units
Pnom total	28.86 kWp	Pnom total	30.0 kWac
		Pnom ratio	0.962

Results summary

Produced Energy	38054 kWh/year	Specific production	1319 kWh/kWp/year	Perf. Ratio PR	91.12 %
Used Energy	458051 kWh/year			Solar Fraction SF	8.31 %

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General parameters

Grid-Connected System — **Building system**

PV Field Orientation

Orientation		**Sheds configuration**	**Models used**	
Fixed plane			Transposition	Perez
Tilt/Azimuth	30 / 18.4 °		Diffuse	Perez, Meteonorm
			Circumsolar	separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
45.0	36.6	48.3	47.5	39.0	34.5	32.4	32.0	33.2	33.1	37.2	39.4	458	MWh

PV Array Characteristics

PV module

Manufacturer	Longi Solar
Model	LR5-72HPH-555M G2
(Original PVsyst database)	
Unit Nom. Power	555 Wp
Number of PV modules	52 units
Nominal (STC)	28.86 kWp
Modules	4 string x 13 In series
At operating cond. (50°C)	
Pmpp	26.45 kWp
U mpp	492 V
I mpp	54 A

Inverter

Manufacturer	SMA
Model	Sunny Tripower 15000TL
(Original PVsyst database)	
Unit Nom. Power	15.0 kWac
Number of inverters	2 units
Total power	30.0 kWac
Operating voltage	240-800 V
Pnom ratio (DC:AC)	0.96
Power sharing within this inverter	

Total PV power

Nominal (STC)	29 kWp
Total	52 modules
Module area	134 m²
Cell area	125 m²

Total inverter power

Total power	30 kWac
Number of inverters	2 units
Pnom ratio	0.96

Array losses

Array Soiling Losses
Average loss Fraction 1.8 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	4.0%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	2.0%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 151 mΩ
Loss Fraction 1.5 % at STC

Module Quality Loss
Loss Fraction -0.8 %

Module mismatch losses
Loss Fraction 2.0 % at MPP

Array losses

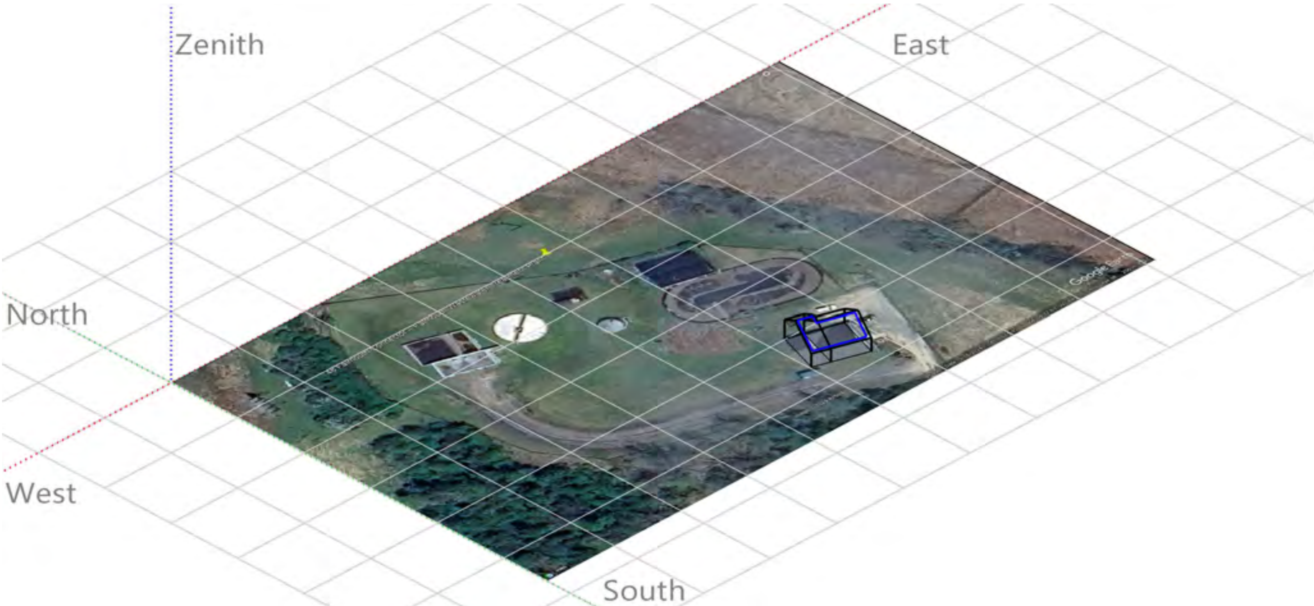
IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

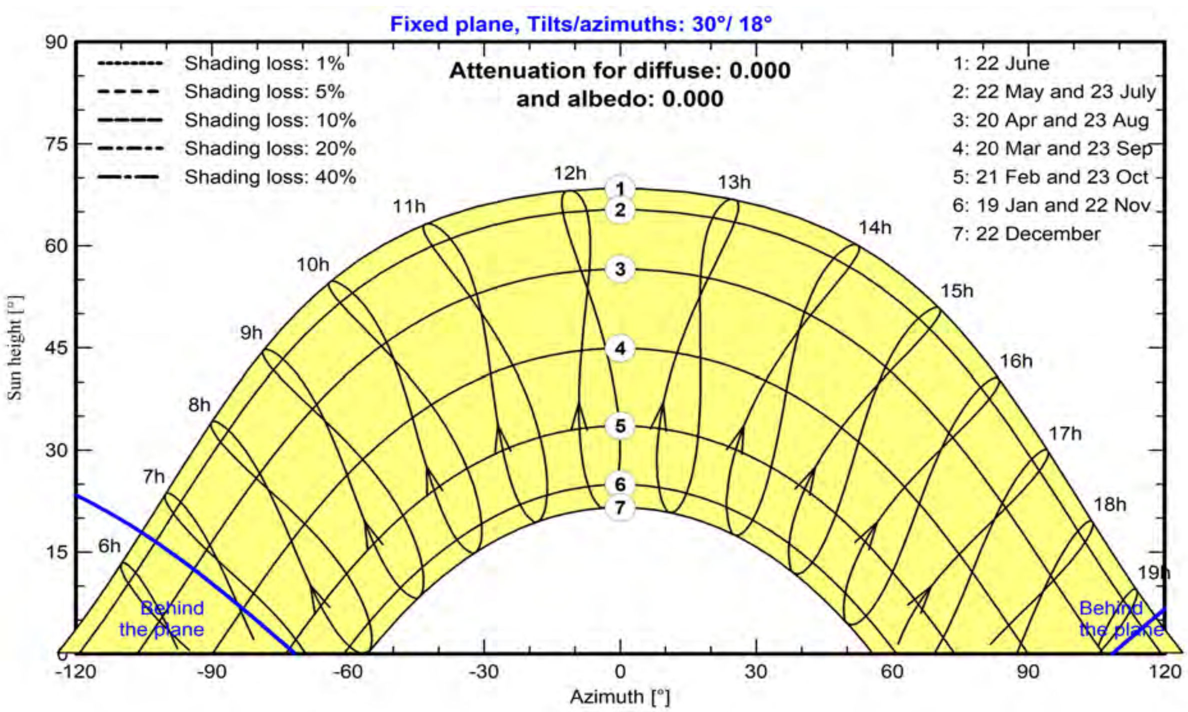
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

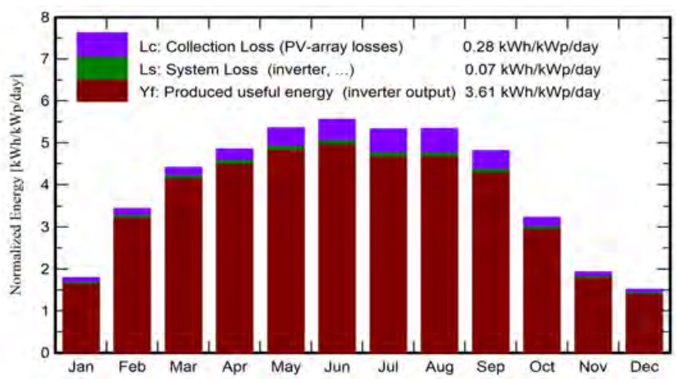


Main results

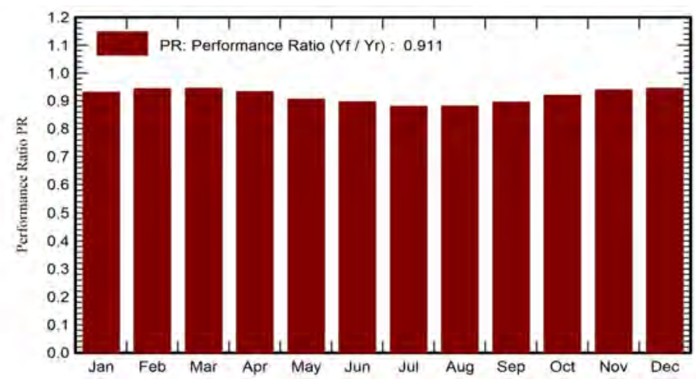
System Production

Produced Energy	38054 kWh/year	Specific production	1319 kWh/kWp/year
Used Energy	458051 kWh/year	Perf. Ratio PR	91.12 %
		Solar Fraction SF	8.31 %

Normalized productions (per installed kWp)



Performance Ratio PR



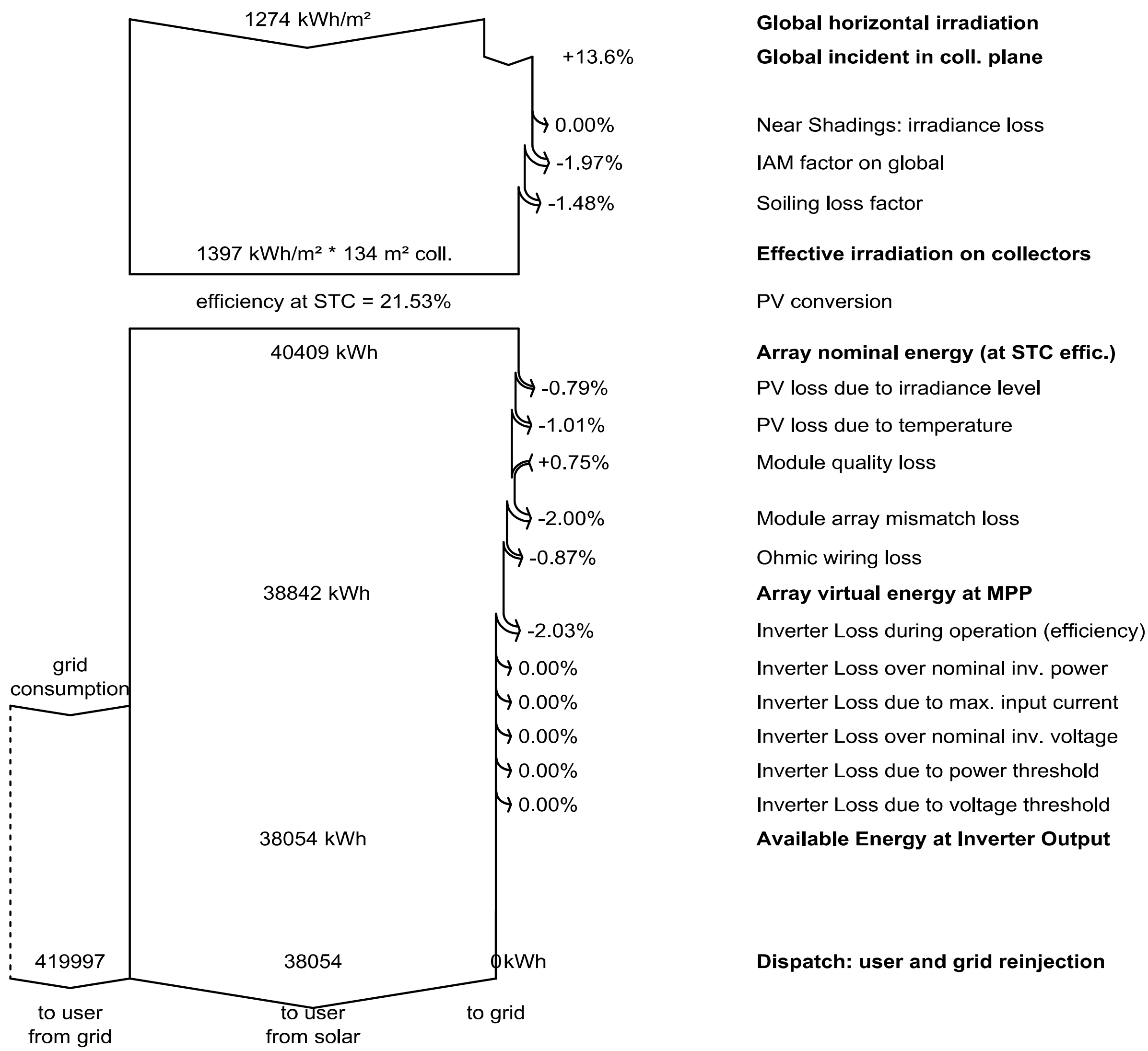
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.2	24.02	-4.91	55.6	51.8	1532	45000	1494	0.000	43506
February	64.4	28.51	-4.58	96.4	91.1	2679	36630	2626	0.000	34004
March	108.3	48.67	-0.72	136.6	131.4	3797	48273	3724	0.000	44548
April	133.1	64.54	5.13	145.5	141.1	3992	47496	3914	0.000	43582
May	165.9	70.24	10.95	166.1	161.0	4428	38960	4341	0.000	34619
June	173.7	88.51	15.86	166.8	161.6	4402	34494	4315	0.000	30179
July	168.7	88.29	20.55	165.3	160.2	4287	32360	4200	0.000	28160
August	155.4	72.91	19.92	165.3	160.4	4289	32041	4206	0.000	27835
September	120.2	49.75	15.50	144.5	140.4	3804	33155	3730	0.000	29425
October	76.6	43.10	9.67	100.3	97.4	2718	33075	2662	0.000	30413
November	40.9	26.34	4.20	57.9	56.2	1607	37214	1568	0.000	35646
December	29.8	19.15	-1.12	46.7	44.9	1308	39352	1273	0.000	38079
Year	1274.1	624.02	7.61	1447.0	1397.4	38842	458051	38054	0.000	419997

Legends

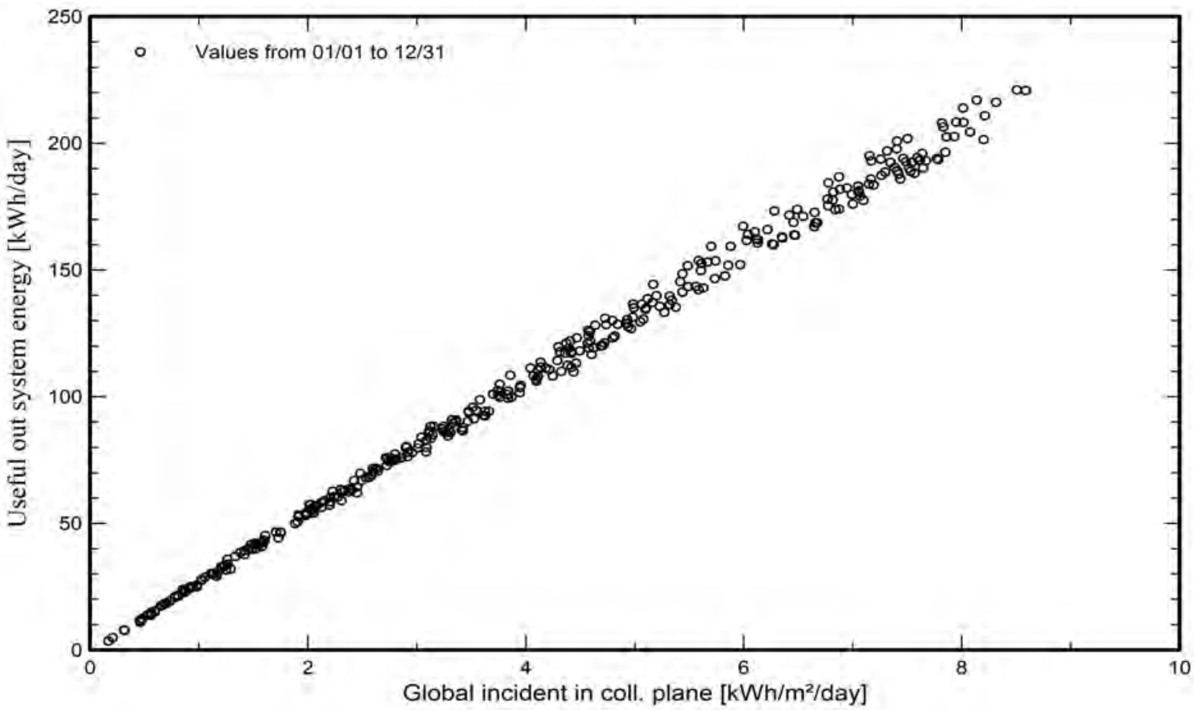
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

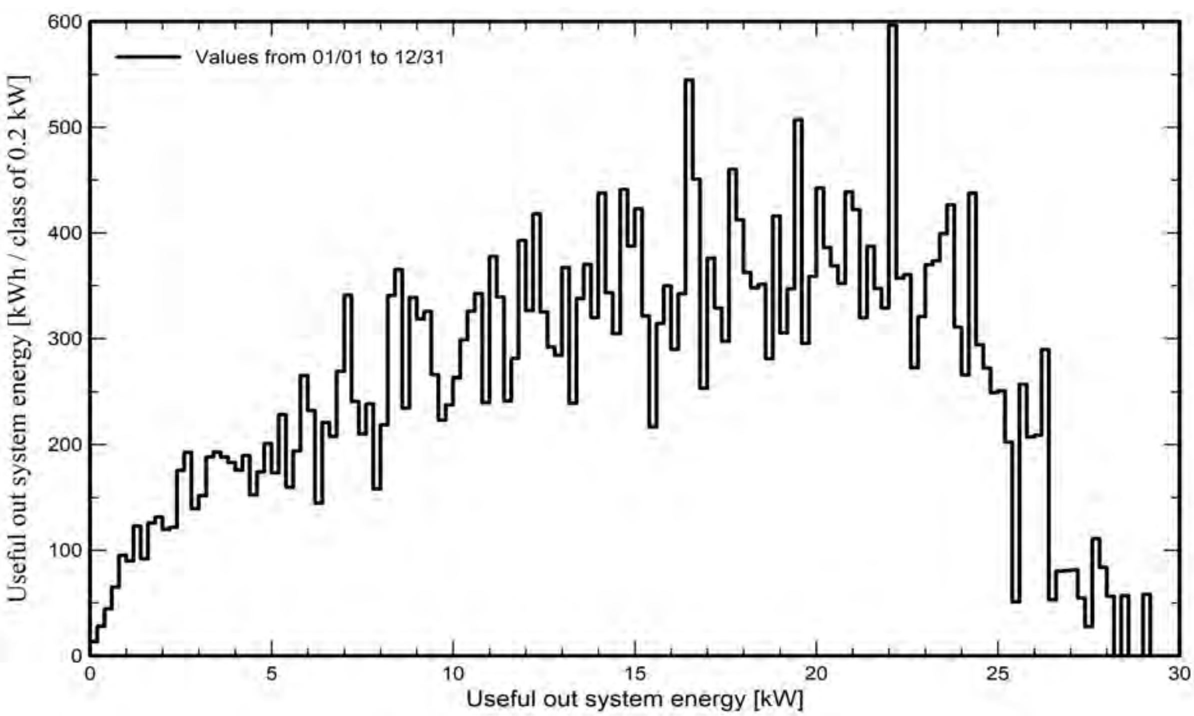


Predef. graphs

Daily Input/Output diagram

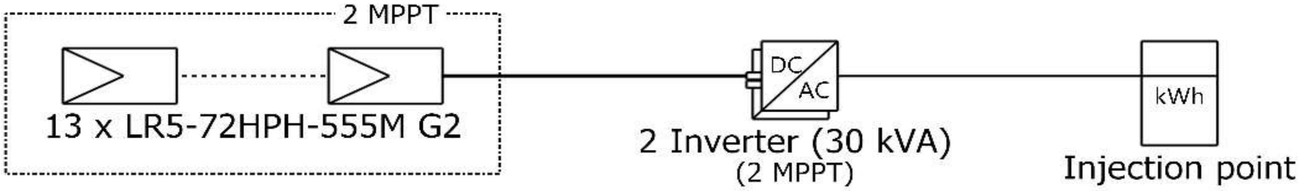


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC3, Simulation date:
08/14/24 16:22
with V7.4.8



PV module	LR5-72HPH-555M G2
Inverter	Sunny Tripower 15000TL
String	13 x LR5-72HPH-555M G2

Falmouth Wastewater Treatment Plant	CBCL Limited (Canada)
VC3 : Falmouth Wastewater Treatment Plant 28.9 Wp Roof MONO	08/14/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: Falmouth Wastewater Treatment Plant

Variant: Falmouth Wastewater Treatment Plant 116 Wp GROUND MONO

Sheds, single array

System power: 116 kWp

48 Falmouth Connector Rd - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site
48 Falmouth Connector Rd
Canada

Situation

Latitude	45.00 °N
Longitude	-64.16 °W
Altitude	13 m
Time zone	UTC-4

Project settings
Albedo 0.20

Weather data
48 Falmouth Connector Rd
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System

Sheds, single array

PV Field Orientation
Fixed planes 2 orientations
Tilts/azimuths 40 / 0 °
40 / 29.4 °

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

System information

PV Array		Inverters	
Nb. of modules	209 units	Nb. of units	2 units
Pnom total	116 kWp	Pnom total	100 kWac
		Pnom ratio	1.160

Results summary

Produced Energy	148386 kWh/year	Specific production	1279 kWh/kWp/year	Perf. Ratio PR	88.68 %
Used Energy	458051 kWh/year			Solar Fraction SF	26.18 %

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Single-line diagram 10

General parameters

Grid-Connected System — **Sheds, single array**

PV Field Orientation

Orientation
Fixed planes: 2 orientations
Tilts/azimuths: 40 / 0 °
40 / 29.4 °

Sheds configuration
Nb. of sheds: 9 units
Averages of diff. arrays

Models used
Transposition: Perez
Diffuse: Perez, Meteonorm
Circumsolar: separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
45.0	36.6	48.3	47.5	39.0	34.5	32.4	32.0	33.2	33.1	37.2	39.4	458	MWh

PV Array Characteristics

PV module
Manufacturer: Longi Solar
Model: LR5-72HPH-555M G2
(Original PVsyst database)
Unit Nom. Power: 555 Wp
Number of PV modules: 209 units
Nominal (STC): 116 kWp

Inverter
Manufacturer: SMA
Model: Sunny Tripower STP50-US-41-Core1
(Original PVsyst database)
Unit Nom. Power: 50.0 kWac
Number of inverters: 2 units
Total power: 100 kWac

Array #1 - PV Array
Orientation: #1
Tilt/Azimuth: 40/0 °
Number of PV modules: 119 units
Nominal (STC): 66.0 kWp
Modules: 7 string x 17 In series

Number of inverters: 1 unit
Total power: 50.0 kWac

At operating cond. (50°C)
Pmpp: 60.5 kWp
U mpp: 643 V
I mpp: 94 A

Operating voltage: 150-800 V
Pnom ratio (DC:AC): 1.32
Power sharing within this inverter

Array #2 - Sub-array #2
Orientation: #2
Tilt/Azimuth: 40/29 °
Number of PV modules: 90 units
Nominal (STC): 50.0 kWp
Modules: 5 string x 18 In series

Number of inverters: 1 unit
Total power: 50.0 kWac

At operating cond. (50°C)
Pmpp: 45.8 kWp
U mpp: 681 V
I mpp: 67 A

Operating voltage: 150-800 V
Pnom ratio (DC:AC): 1.00
Power sharing within this inverter

Total PV power
Nominal (STC): 116 kWp
Total: 209 modules
Module area: 540 m²
Cell area: 501 m²

Total inverter power
Total power: 100 kWac
Number of inverters: 2 units
Pnom ratio: 1.16

Array losses

Array Soiling Losses
Average loss Fraction 1.8 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	4.0%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	2.0%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

Module Quality Loss
Loss Fraction -0.8 %

Module mismatch losses
Loss Fraction 2.0 % at MPP

IAM loss factor
Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

DC wiring losses

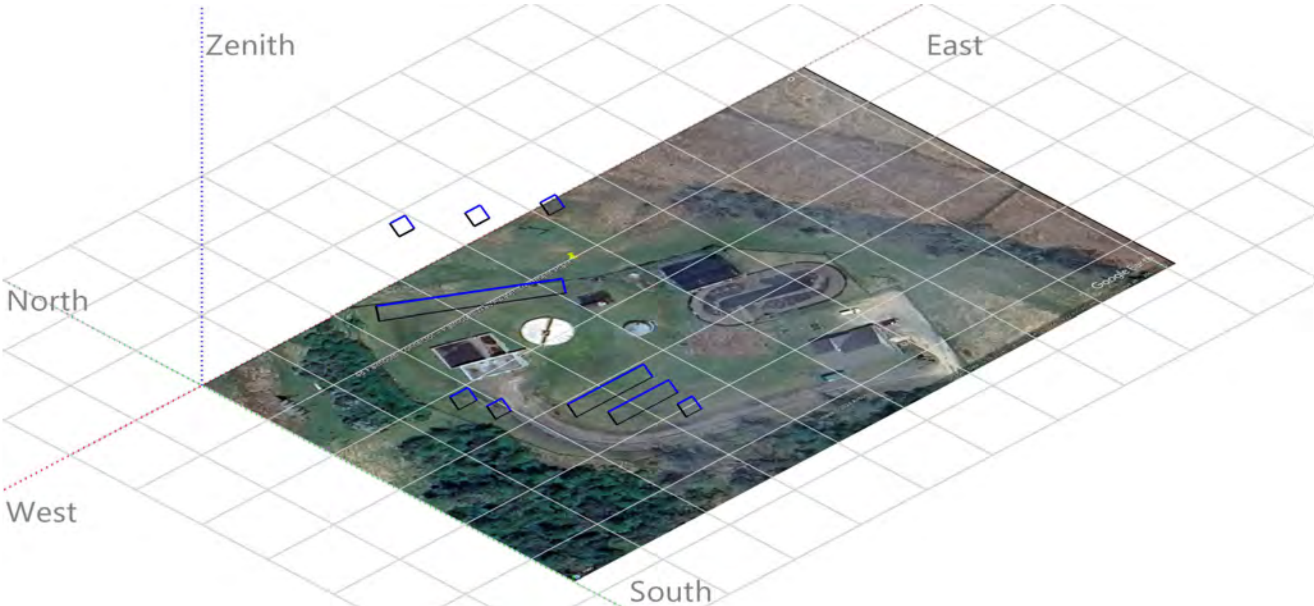
Global wiring resistance 10 mΩ
Loss Fraction 1.5 % at STC

Array #1 - PV Array
Global array res. 113 mΩ
Loss Fraction 1.5 % at STC

Array #2 - Sub-array #2
Global array res. 168 mΩ
Loss Fraction 1.5 % at STC

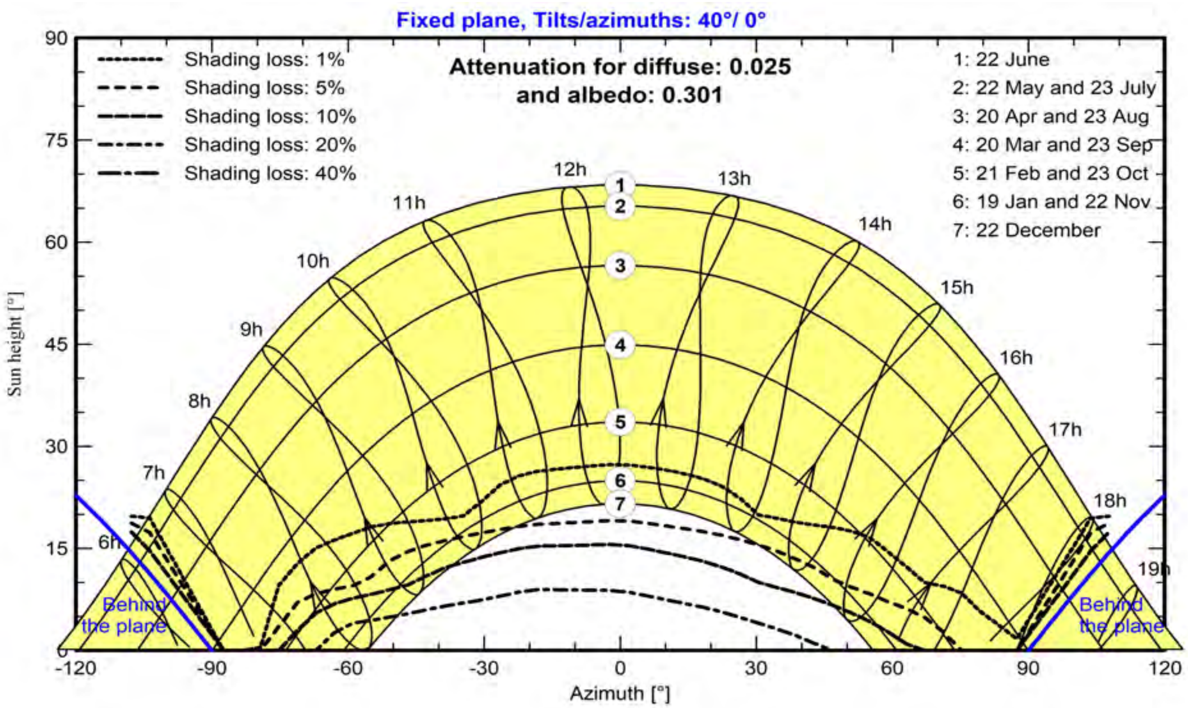
Near shadings parameter

Perspective of the PV-field and surrounding shading scene

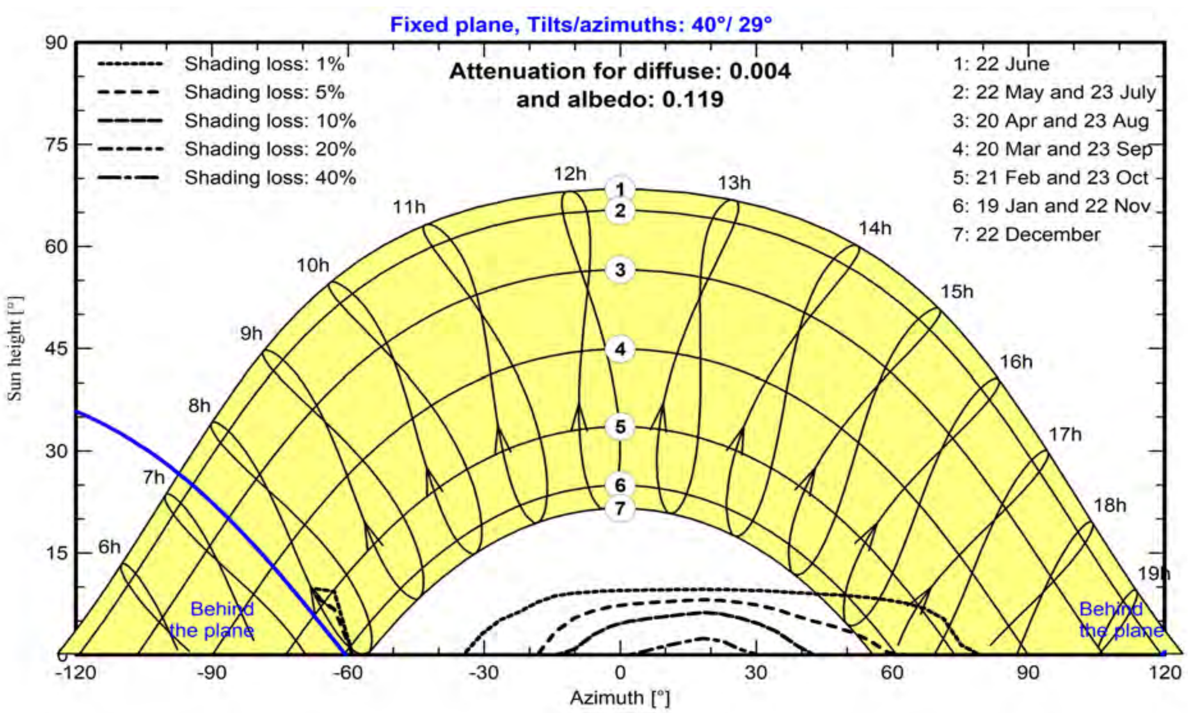


Iso-shadings diagram

Orientation #1



Orientation #2

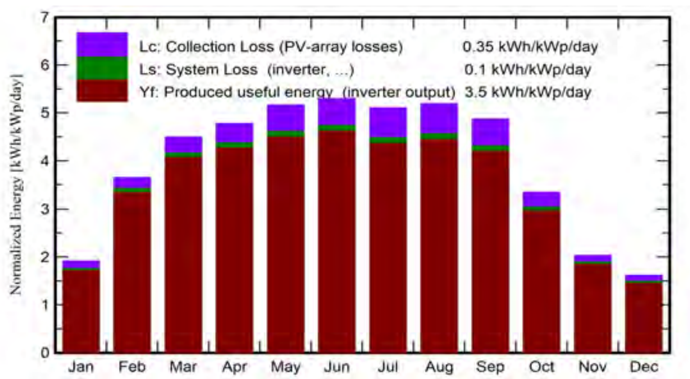


Main results

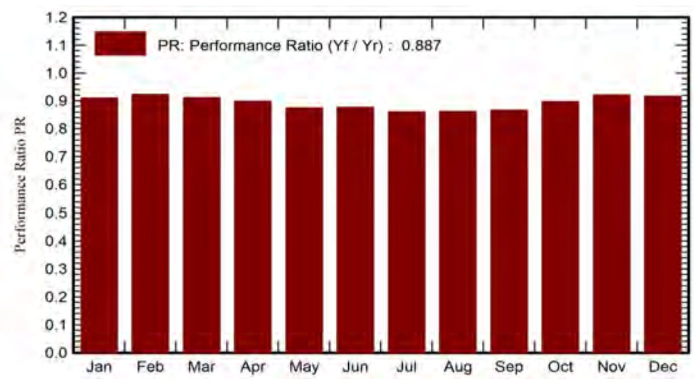
System Production

Produced Energy	148386 kWh/year	Specific production	1279 kWh/kWp/year
Used Energy	458051 kWh/year	Perf. Ratio PR	88.68 %
		Solar Fraction SF	26.18 %

Normalized productions (per installed kWp)



Performance Ratio PR



Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.2	24.02	-4.91	59.3	54.2	6426	45000	5914	342	39086
February	64.4	28.51	-4.58	102.1	95.8	11204	36630	8961	1967	27669
March	108.3	48.67	-0.72	139.2	133.2	15079	48273	12921	1786	35352
April	133.1	64.54	5.13	143.3	137.7	15325	47496	13380	1552	34116
May	165.9	70.24	10.95	160.1	153.4	16688	38960	12800	3439	26160
June	173.7	88.51	15.86	158.9	152.0	16603	34494	12730	3429	21765
July	168.7	88.29	20.55	158.2	151.4	16221	32360	11887	3892	20474
August	155.4	72.91	19.92	160.9	154.7	16520	32041	11557	4518	20484
September	120.2	49.75	15.50	146.1	141.1	15109	33155	10628	4074	22527
October	76.6	43.10	9.67	103.4	99.7	11049	33075	8518	2241	24557
November	40.9	26.34	4.20	61.0	58.5	6706	37214	5827	693	31387
December	29.8	19.15	-1.12	50.1	47.0	5486	39352	4808	520	34544
Year	1274.1	624.02	7.61	1442.6	1378.8	152416	458051	119931	28455	338120

Legends

GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

PVsyst V7.4.8
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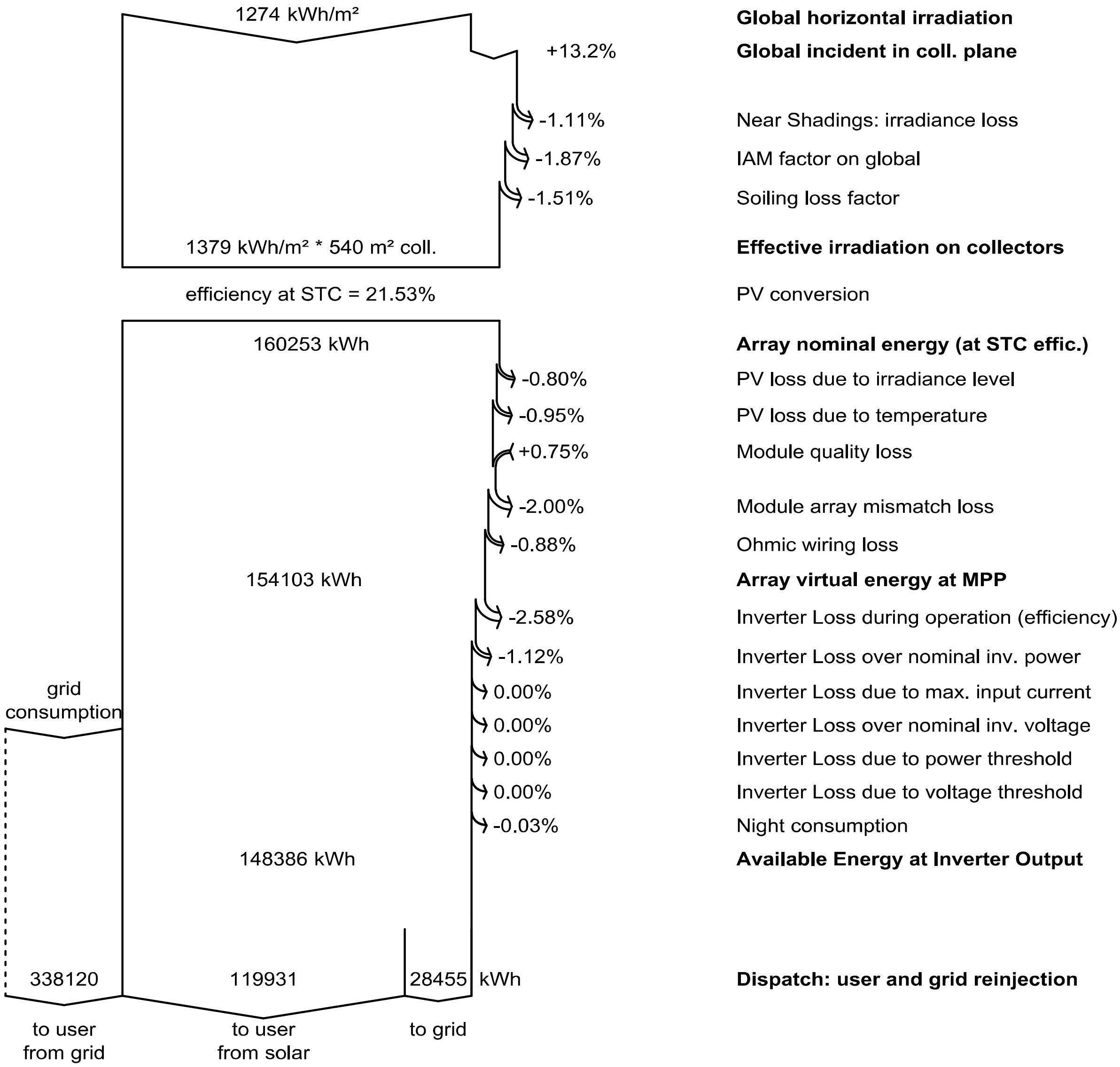
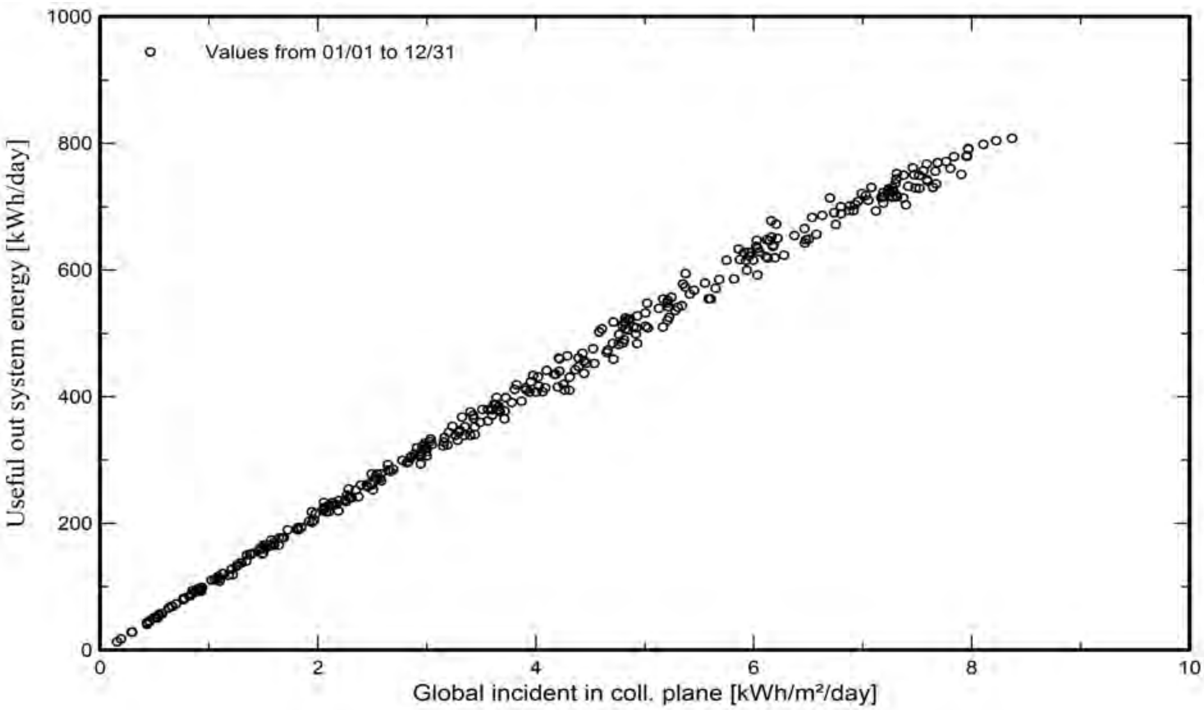
with V7.4.8

Loss diagram

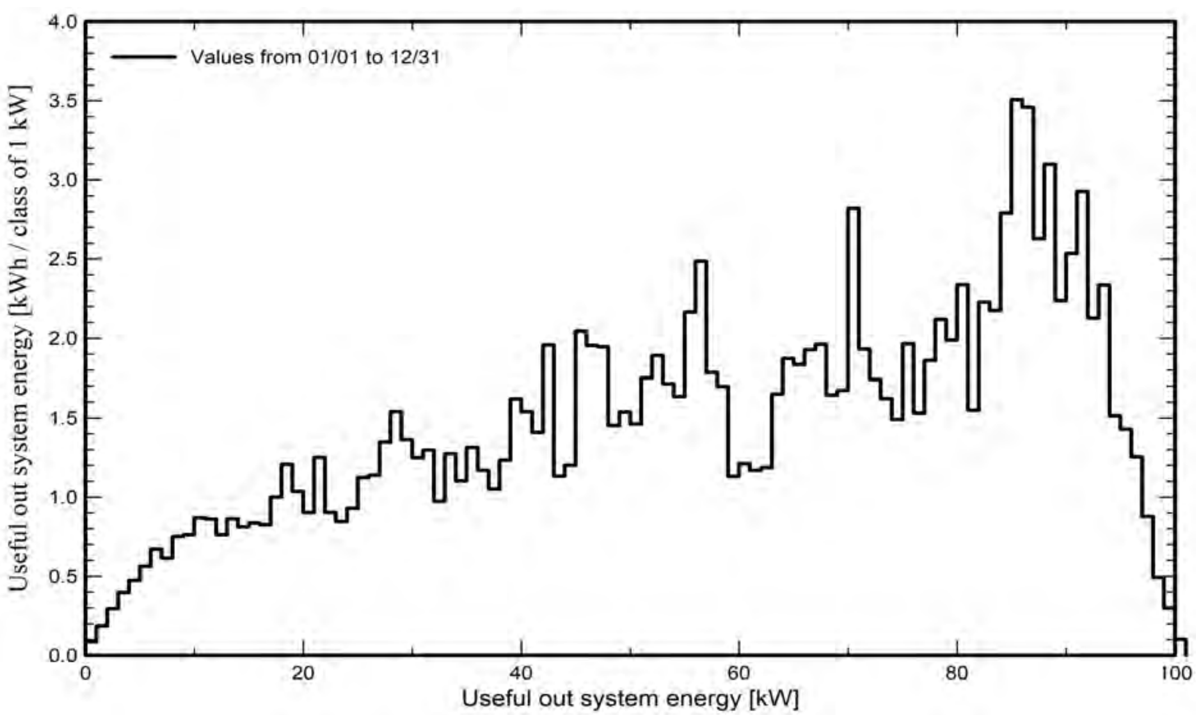


Predef. graphs

Daily Input/Output diagram



System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC0, Simulation date:
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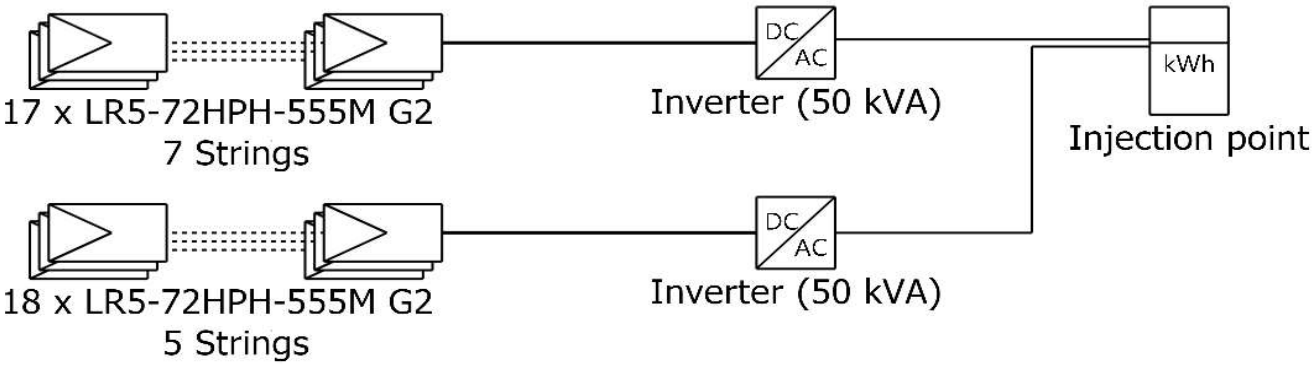
with V7.4.8



PV module	LR5-72HPH-555M G2
Inverter	Sunny Tripower STP50-US-41-Core1
String 1	17 x LR5-72HPH-555M G2
String 2	18 x LR5-72HPH-555M G2

Falmouth Wastewater Treatmen t Plant	CBCL Limited (Can ada)
VC0 : Falmouth Wastewater Treatment Plant 116 Wp GROUND MONO	08/14/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: Falmouth Wastewater Treatment Plant

Variant: Falmouth Wastewater Treatment Plant 49.5 Wp GROUND M Bifacial 2of2

Sheds, single array

System power: 49.5 kWp

48 Falmouth Connector Rd - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site	Situation		Project settings	
48 Falmouth Connector Rd	Latitude	45.00 °N	Albedo	0.20
Canada	Longitude	-64.16 °W		
	Altitude	13 m		
	Time zone	UTC-4		

Weather data
48 Falmouth Connector Rd
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System — **Sheds, single array**

PV Field Orientation		Near Shadings	User's needs
Fixed plane		Linear shadings : Fast (table)	Monthly values
Tilt/Azimuth	40 / 29.4 °		

System information

PV Array		Inverters	
Nb. of modules	90 units	Nb. of units	1 unit
Pnom total	49.5 kWp	Pnom total	50.0 kWac
		Pnom ratio	0.990

Results summary

Produced Energy	70598 kWh/year	Specific production	1426 kWh/kWp/year	Perf. Ratio PR	100.45 %
Used Energy	458051 kWh/year			Solar Fraction SF	15.40 %

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General parameters

Grid-Connected System

Sheds, single array

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 40 / 29.4 °

Sheds configuration
Nb. of sheds 2 units
Single array

Sizes
Sheds spacing 20.0 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 22.9 %
Top inactive band 0.02 m
Bottom inactive band 0.02 m

Shading limit angle
Limit profile angle 10.2 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Bifacial system
Model 2D Calculation
unlimited sheds

Bifacial model geometry
Sheds spacing 20.00 m
Sheds width 4.62 m
Limit profile angle 10.2 °
GCR 23.1 %
Height above ground 1.50 m

Bifacial model definitions
Ground albedo 0.30
Bifaciality factor 70 %
Rear shading factor 5.0 %
Rear mismatch loss 10.0 %
Shed transparent fraction 0.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
45.0	36.6	48.3	47.5	39.0	34.5	32.4	32.0	33.2	33.1	37.2	39.4	458	MWh

PV Array Characteristics

PV module
Manufacturer Longi Solar
Model LR5-72HBD-550M G2 Bifacial
(Original PVsyst database)
Unit Nom. Power 550 Wp
Number of PV modules 90 units
Nominal (STC) 49.5 kWp
Modules 5 string x 18 In series

At operating cond. (50°C)
Pmpp 45.3 kWp
U mpp 680 V
I mpp 67 A

Inverter
Manufacturer SMA
Model Sunny Tripower STP50-US-41-Core1
(Original PVsyst database)
Unit Nom. Power 50.0 kWac
Number of inverters 1 unit
Total power 50.0 kWac
Operating voltage 150-800 V
Pnom ratio (DC:AC) 0.99
Power sharing within this inverter

Total PV power
Nominal (STC) 50 kWp
Total 90 modules
Module area 232 m²
Cell area 216 m²

Total inverter power
Total power 50 kWac
Number of inverters 1 unit
Pnom ratio 0.99

Array losses

Array Soiling Losses

Average loss Fraction 1.8 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	4.0%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	2.0%

Thermal Loss factor

Module temperature according to irradiance

Uc (const) 29.0 W/m²K

Uv (wind) 0.0 W/m²K/m/s

DC wiring losses

Global array res. 169 mΩ

Loss Fraction 1.5 % at STC

Module Quality Loss

Loss Fraction -0.8 %

Module mismatch losses

Loss Fraction 2.0 % at MPP

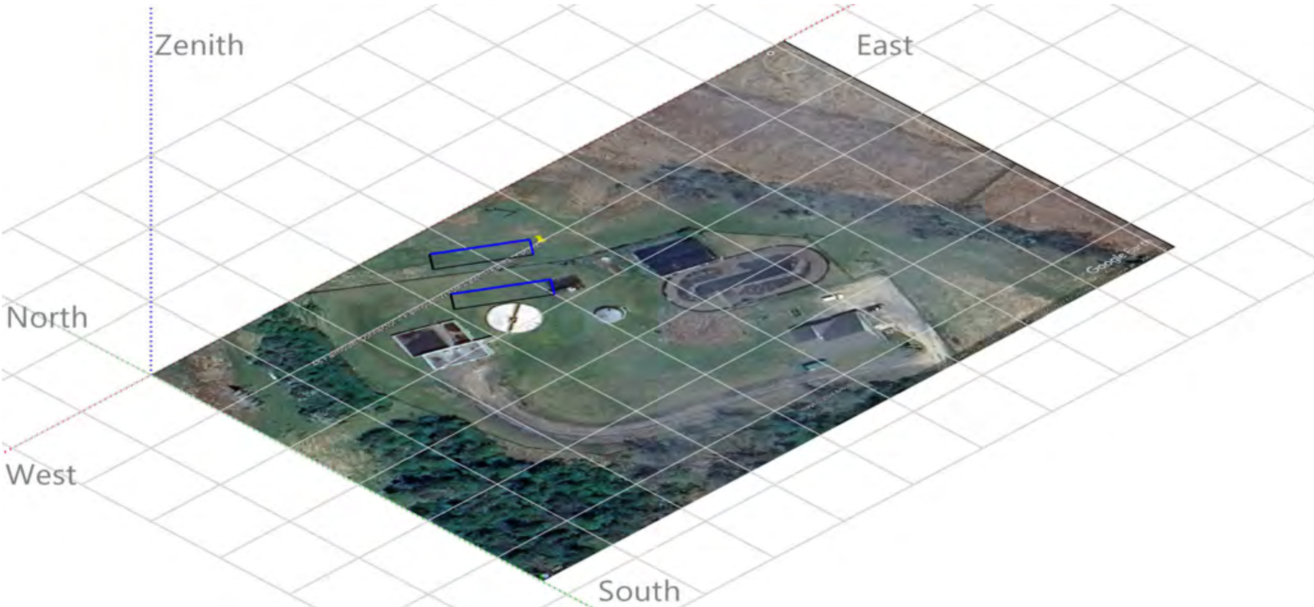
IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

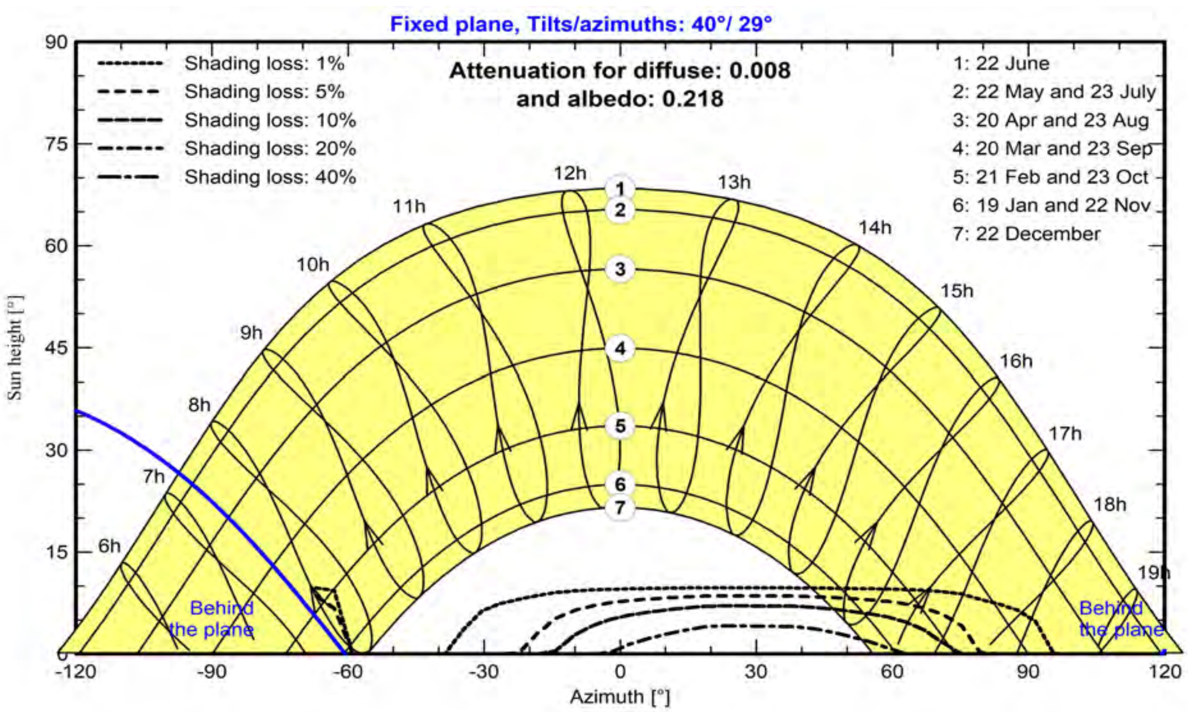
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

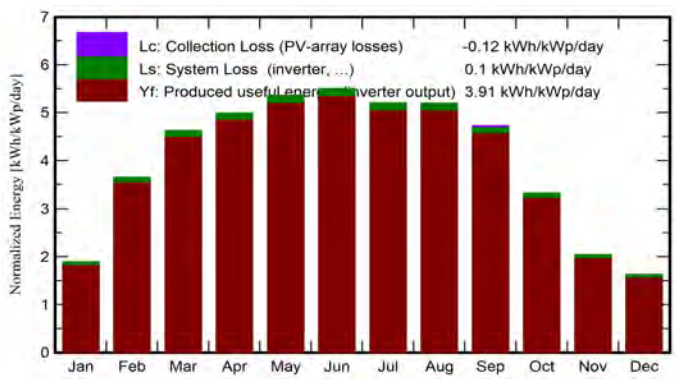


Main results

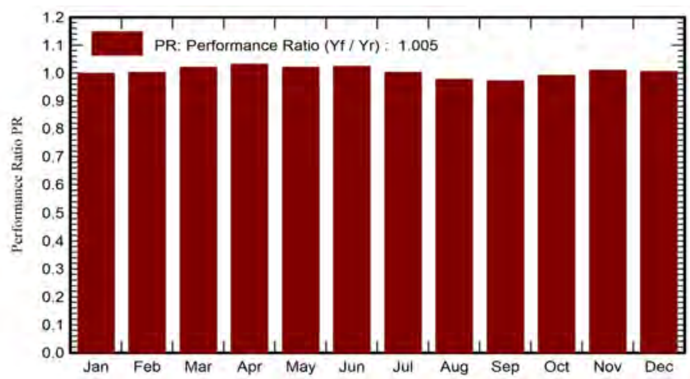
System Production

Produced Energy	70598 kWh/year	Specific production	1426 kWh/kWp/year
Used Energy	458051 kWh/year	Perf. Ratio PR	100.45 %
		Solar Fraction SF	15.40 %

Normalized productions (per installed kWp)



Performance Ratio PR



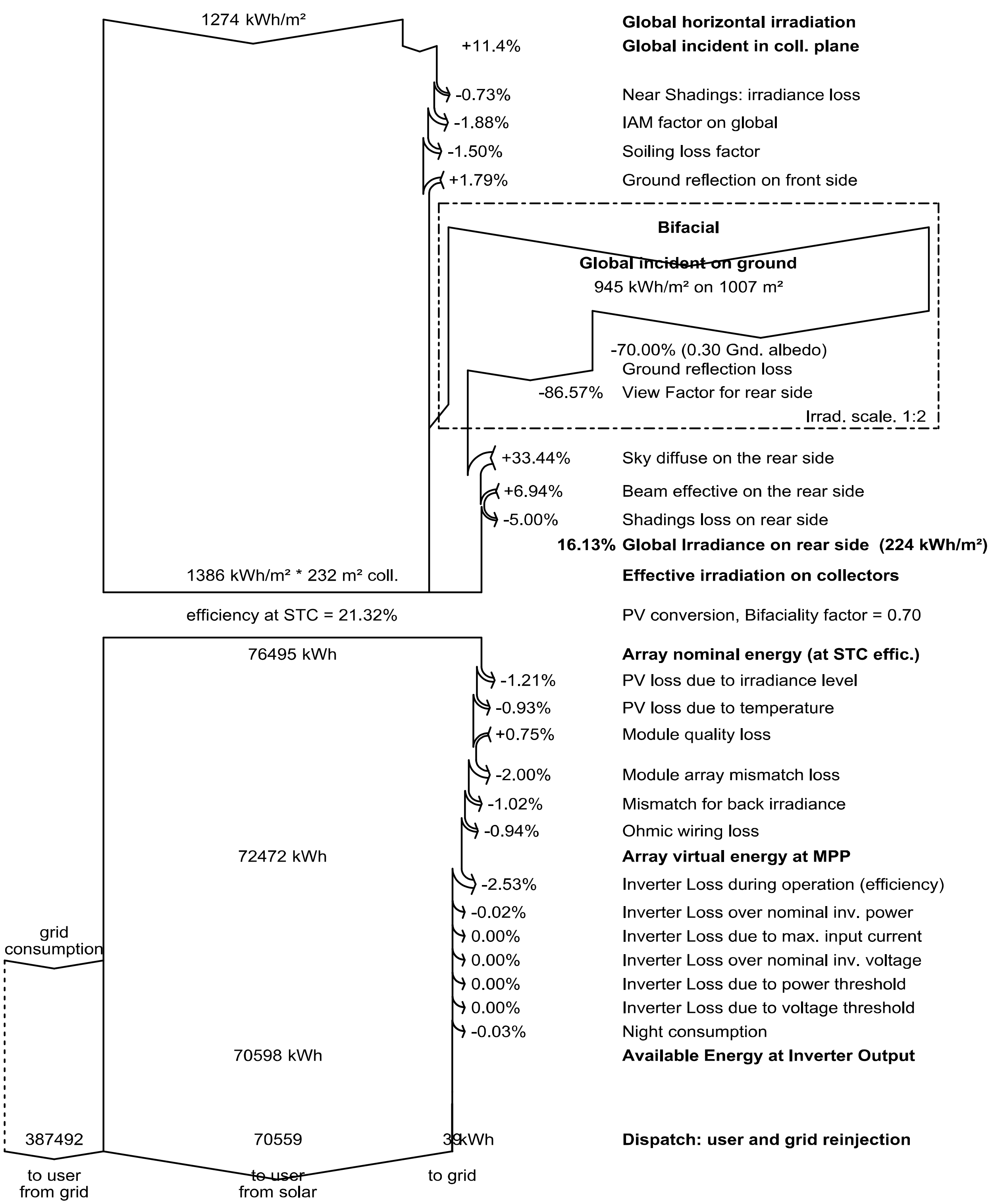
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.2	24.02	-4.91	57.3	53.6	2907	45000	2835	-2.45	42165
February	64.4	28.51	-4.58	99.4	94.5	5050	36630	4933	-2.03	31697
March	108.3	48.67	-0.72	137.1	133.5	7092	48273	6924	-2.01	41348
April	133.1	64.54	5.13	141.6	139.2	7413	47496	7231	-1.70	40265
May	165.9	70.24	10.95	158.6	155.7	8224	38960	8012	-1.55	30948
June	173.7	88.51	15.86	157.3	154.4	8175	34494	7967	-1.40	26528
July	168.7	88.29	20.55	156.9	154.1	7988	32360	7769	9.84	24592
August	155.4	72.91	19.92	160.7	158.1	7978	32041	7743	27.10	24298
September	120.2	49.75	15.50	141.8	139.4	7000	33155	6814	1.32	26341
October	76.6	43.10	9.67	101.2	99.1	5096	33075	4948	16.81	28127
November	40.9	26.34	4.20	59.1	57.7	3032	37214	2953	-2.32	34261
December	29.8	19.15	-1.12	48.8	47.0	2499	39352	2431	-2.50	36921
Year	1274.1	624.02	7.61	1419.8	1386.4	72454	458051	70559	39.11	387492

Legends

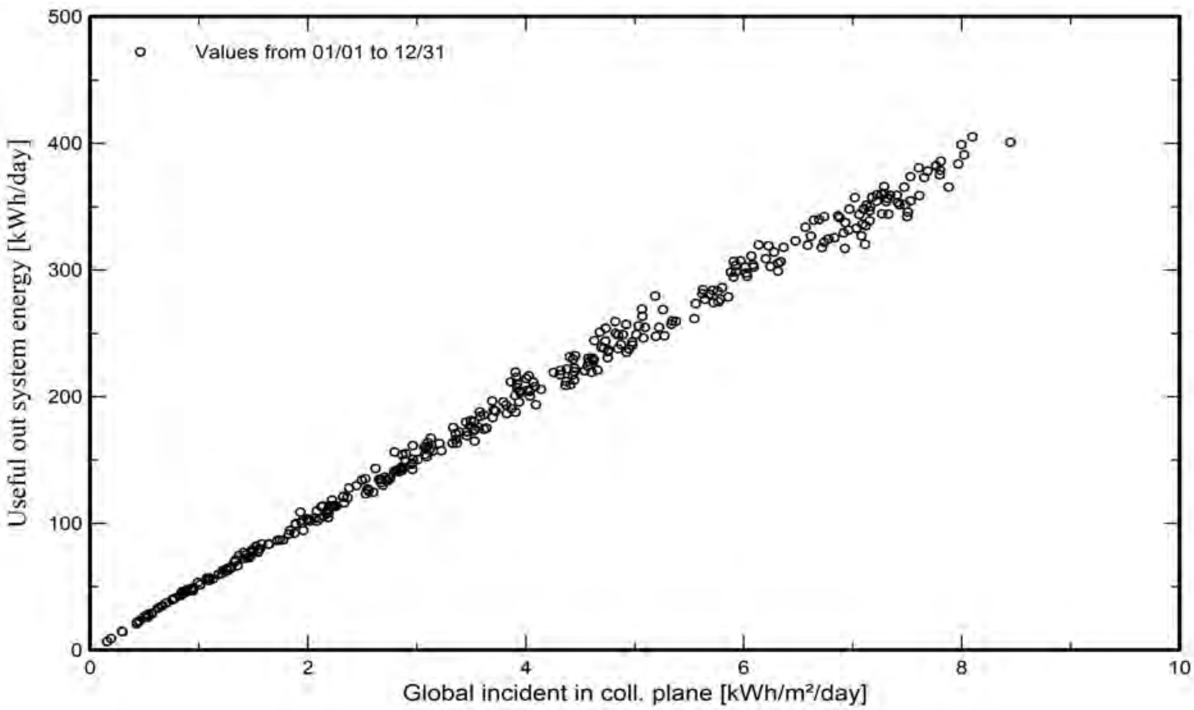
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

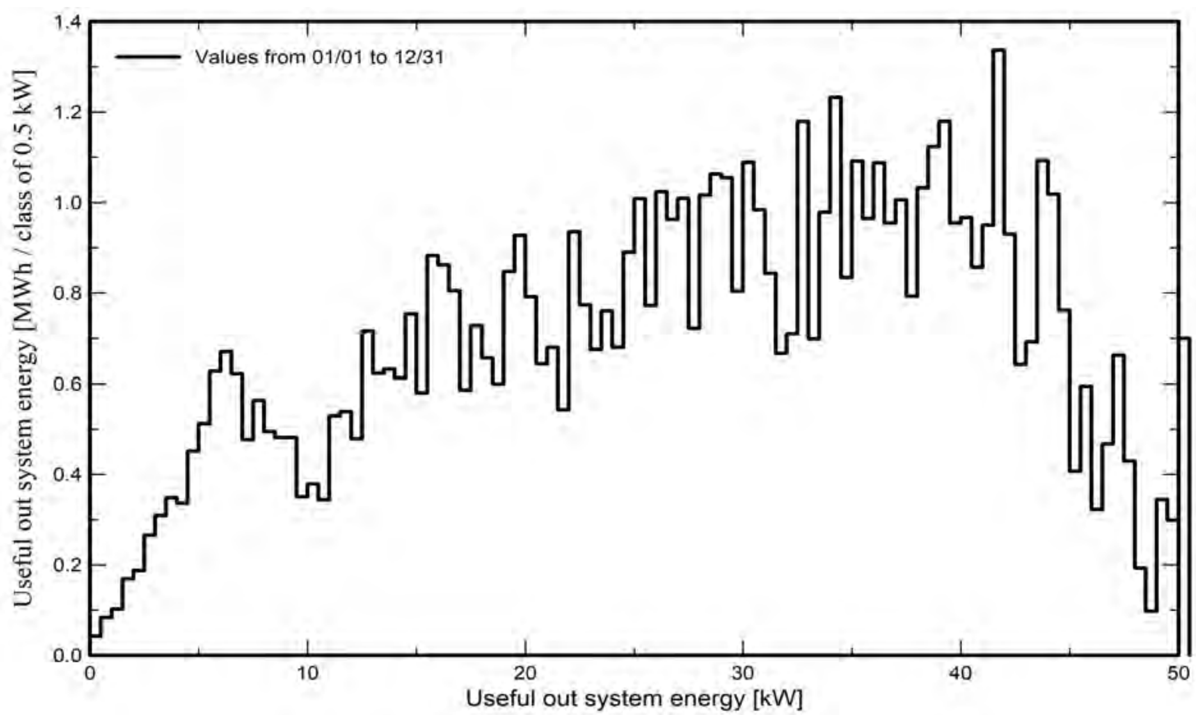


Predef. graphs

Daily Input/Output diagram

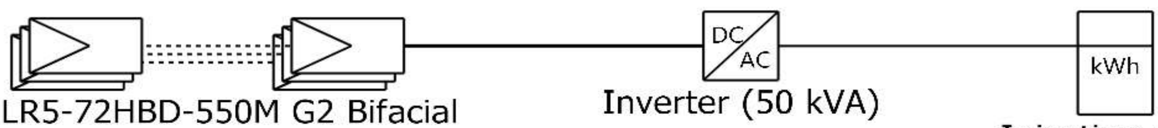


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC2, Simulation date:
08/14/24 15:49
with V7.4.8



PV module	LR5-72HBD-550M G2 Bifacial
Inverter	Sunny Tripower STP50-US-41-Core1
String	18 x LR5-72HBD-550M G2 Bifacial

Falmouth Wastewater Treatmen t Plant	CBCL Limited (Can ada)
VC2 : Falmouth Wastewater Treatment Plant 49.5 Wp GROUND M Bifacial 2of	08/14/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: Falmouth Wastewater Treatment Plant

Variant: Falmouth Wastewater Treatment Plant 65.5 Wp GROUND Bifacial 1of2

Sheds on ground

System power: 65.5 kWp

48 Falmouth Connector Rd - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site		Situation		Project settings	
48 Falmouth Connector Rd		Latitude	45.00 °N	Albedo	0.20
Canada		Longitude	-64.16 °W		
		Altitude	13 m		
		Time zone	UTC-4		

Weather data
48 Falmouth Connector Rd
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System

Sheds on ground

PV Field Orientation		Near Shadings	User's needs
Fixed plane		Linear shadings : Fast (table)	Monthly values
Tilt/Azimuth	40 / 0 °		

System information

PV Array		Inverters	
Nb. of modules	119 units	Nb. of units	1 unit
Pnom total	65.5 kWp	Pnom total	50.0 kWac
		Pnom ratio	1.309

Results summary

Produced Energy	89199 kWh/year	Specific production	1363 kWh/kWp/year	Perf. Ratio PR	93.35 %
Used Energy	458051 kWh/year			Solar Fraction SF	19.19 %

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General parameters

Grid-Connected System

Sheds on ground

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Sheds configuration
Nb. of sheds 5 units
Averages of diff. arrays

Sizes
Sheds spacing 10.4 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 44.2 %
Top inactive band 0.02 m
Bottom inactive band 0.02 m

Shading limit angle
Limit profile angle 23.4 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Bifacial system
Model 2D Calculation
unlimited sheds

Bifacial model geometry
Sheds spacing 10.36 m
Sheds width 4.62 m
Limit profile angle 23.4 °
GCR 44.6 %
Height above ground 1.50 m

Bifacial model definitions
Ground albedo 0.30
Bifaciality factor 70 %
Rear shading factor 5.0 %
Rear mismatch loss 10.0 %
Shed transparent fraction 0.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
45.0	36.6	48.3	47.5	39.0	34.5	32.4	32.0	33.2	33.1	37.2	39.4	458	MWh

PV Array Characteristics

PV module
Manufacturer Longi Solar
Model LR5-72HBD-550M G2 Bifacial
(Original PVsyst database)
Unit Nom. Power 550 Wp
Number of PV modules 119 units
Nominal (STC) 65.5 kWp
Modules 7 string x 17 In series

At operating cond. (50°C)
Pmpp 60.0 kWp
U mpp 642 V
I mpp 93 A

Inverter
Manufacturer SMA
Model Sunny Tripower STP50-US-41-Core1
(Original PVsyst database)
Unit Nom. Power 50.0 kWac
Number of inverters 1 unit
Total power 50.0 kWac
Operating voltage 150-800 V
Pnom ratio (DC:AC) 1.31
Power sharing within this inverter

Total PV power
Nominal (STC) 65 kWp
Total 119 modules
Module area 307 m²
Cell area 285 m²

Total inverter power
Total power 50 kWac
Number of inverters 1 unit
Pnom ratio 1.31

Array losses

Array Soiling Losses
Average loss Fraction 1.8 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	4.0%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	2.0%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 114 mΩ
Loss Fraction 1.5 % at STC

Module Quality Loss
Loss Fraction -0.8 %

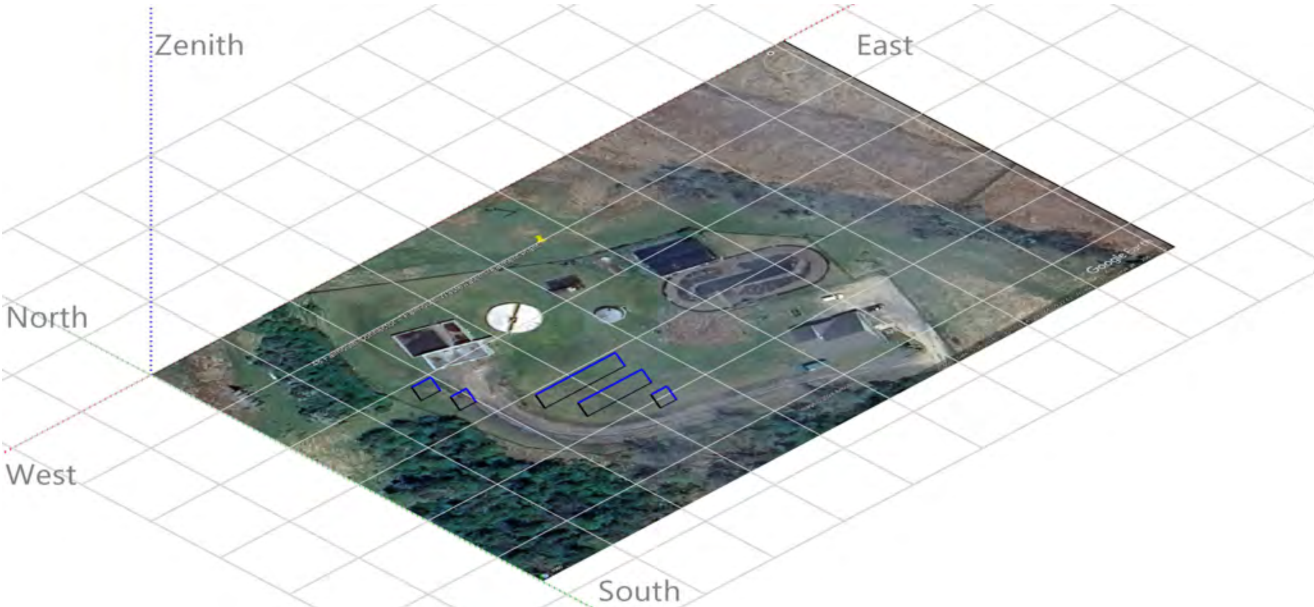
Module mismatch losses
Loss Fraction 2.0 % at MPP

IAM loss factor
Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

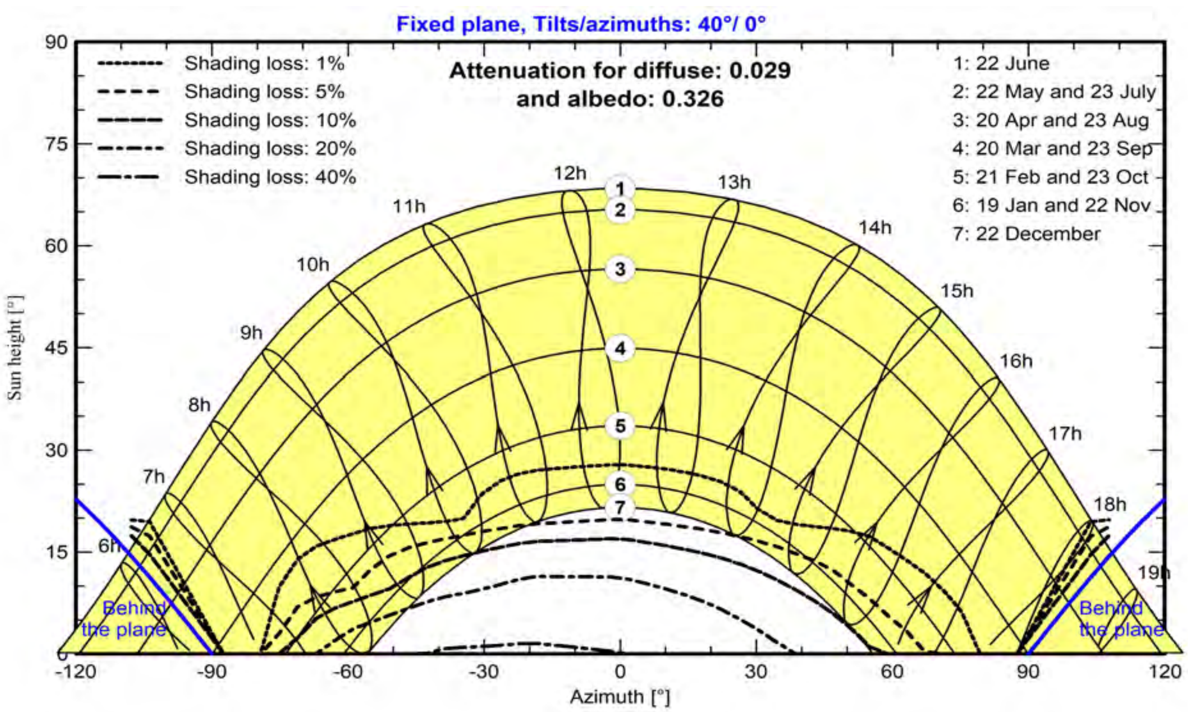
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

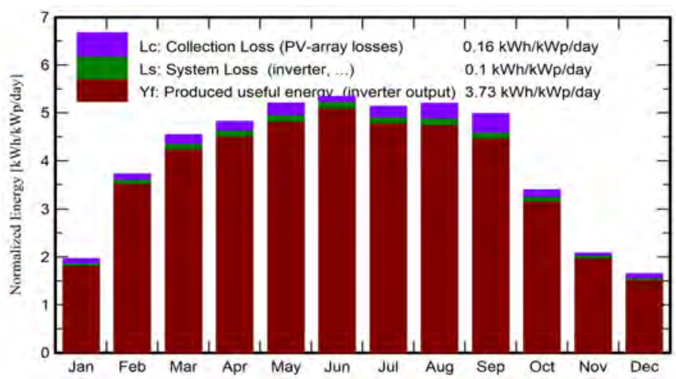


Main results

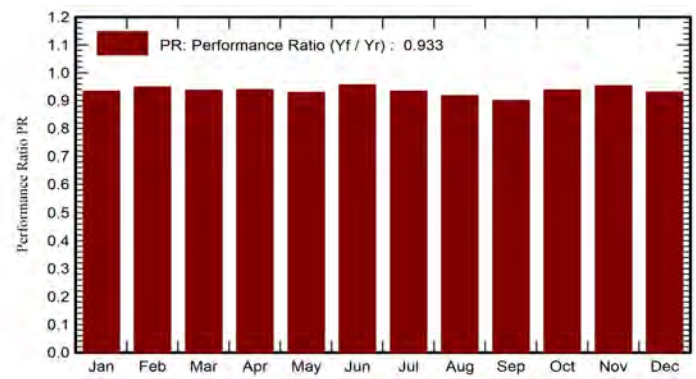
System Production

Produced Energy	89199 kWh/year	Specific production	1363 kWh/kWp/year
Used Energy	458051 kWh/year	Perf. Ratio PR	93.35 %
		Solar Fraction SF	19.19 %

Normalized productions (per installed kWp)



Performance Ratio PR



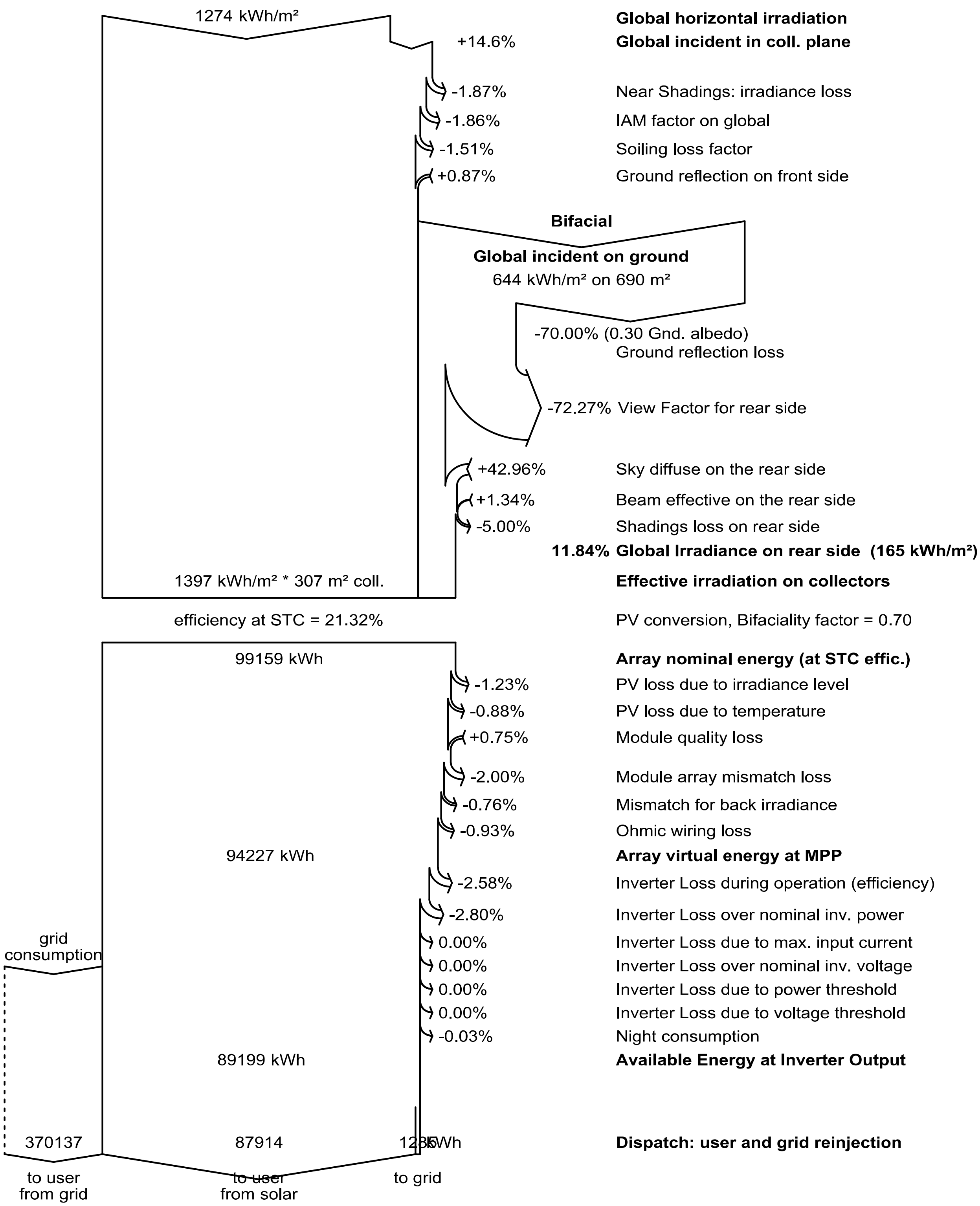
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.2	24.02	-4.91	60.8	54.8	3814	45000	3715	-2.4	41285
February	64.4	28.51	-4.58	104.1	97.6	6635	36630	6468	-2.0	30162
March	108.3	48.67	-0.72	140.8	134.8	8863	48273	8640	-2.0	39632
April	133.1	64.54	5.13	144.6	139.3	9125	47496	8889	-1.7	38607
May	165.9	70.24	10.95	161.3	155.4	10080	38960	9809	-1.5	29151
June	173.7	88.51	15.86	160.2	154.2	10305	34494	9923	102.6	24571
July	168.7	88.29	20.55	159.1	153.2	10002	32360	9373	354.5	22988
August	155.4	72.91	19.92	161.1	155.4	9942	32041	9234	435.6	22807
September	120.2	49.75	15.50	149.4	144.5	9049	33155	8555	246.6	24600
October	76.6	43.10	9.67	105.1	101.3	6625	33075	6290	160.4	26785
November	40.9	26.34	4.20	62.5	59.4	4012	37214	3905	-2.3	33309
December	29.8	19.15	-1.12	51.1	46.9	3201	39352	3113	-2.5	36239
Year	1274.1	624.02	7.61	1460.0	1396.8	91653	458051	87914	1285.1	370137

Legends

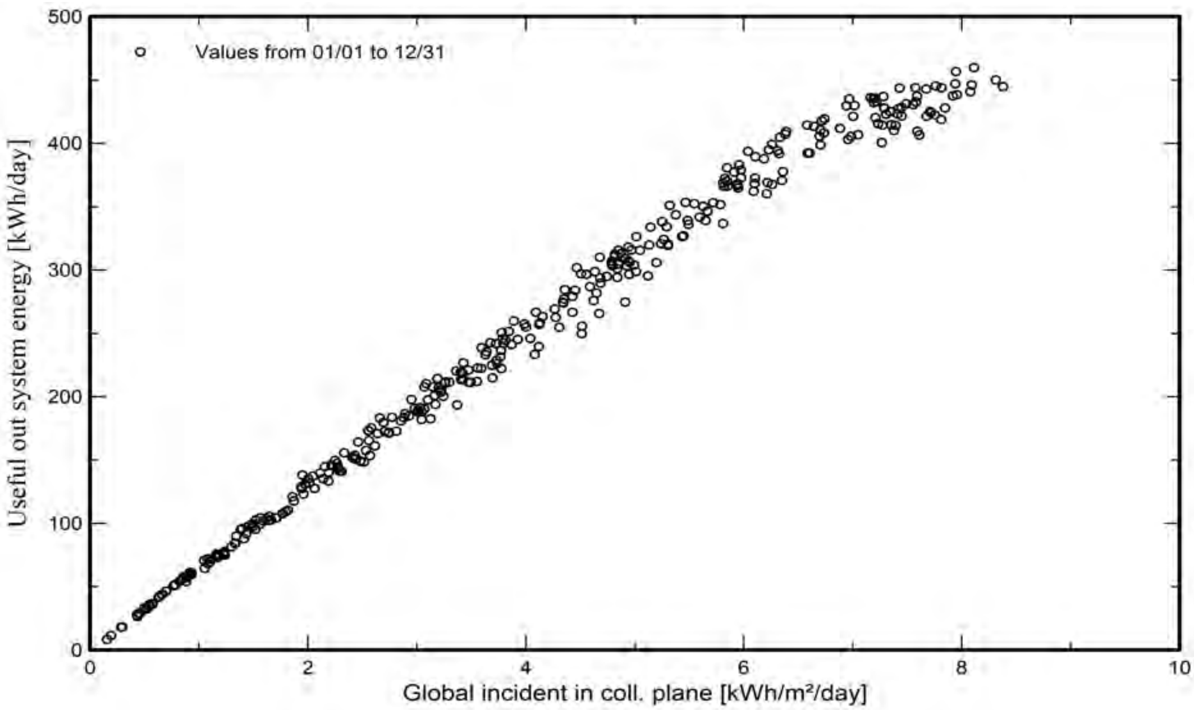
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

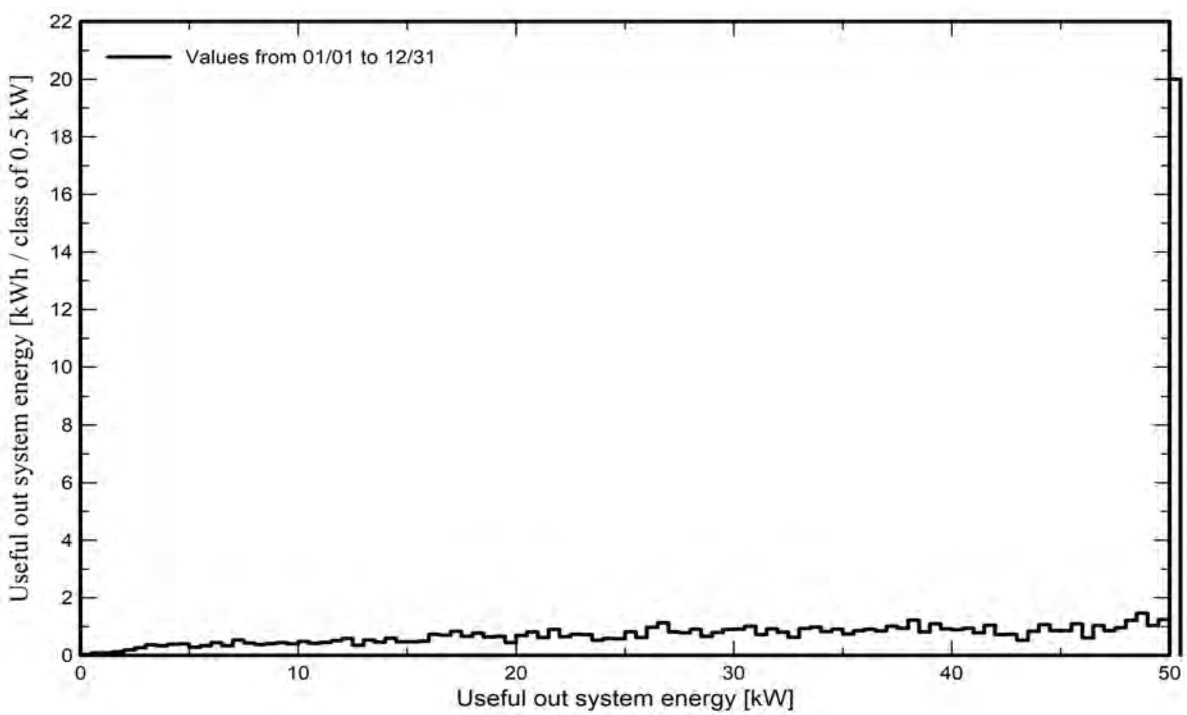


Predef. graphs

Daily Input/Output diagram



System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC1, Simulation date:
08/14/24 15:41
with V7.4.8

PV module	LR5-72HBD-550M G2 Bifacial
Inverter	Sunny Tripower STP50-US-41-Core1
String	17 x LR5-72HBD-550M G2 Bifacial

Falmouth Wastewater Treatment Plant	CBCL Limited (Canada)
VC1 : Falmouth Wastewater Treatment Plant 65.5 Wp GROUND Bifacial 1of2	08/14/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 3 Lagoon Dr

Variant: 3 Lagoon Dr 308 kw MONO-2

Sheds on ground

System power: 308 kWp

Windsor - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site	Situation		Project settings	
Windsor	Latitude	44.99 °N	Albedo	0.20
Canada	Longitude	-64.15 °W		
	Altitude	14 m		
	Time zone	UTC-4		

Weather data
Windsor
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System — **Sheds on ground**

PV Field Orientation		Near Shadings	User's needs
Fixed planes	2 orientations	Linear shadings : Fast (table)	Monthly values
Tilts/azimuths	40 / 6.7 °		
	40 / 0 °		

System information

PV Array		Inverters	
Nb. of modules	558 units	Nb. of units	5 units
Pnom total	308 kWp	Pnom total	275 kWac
		Pnom ratio	1.122

Results summary

Produced Energy	404329 kWh/year	Specific production	1311 kWh/kWp/year	Perf. Ratio PR	90.24 %
Used Energy	403298 kWh/year			Solar Fraction SF	37.99 %

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General parameters

Grid-Connected System — **Sheds on ground**

PV Field Orientation

Orientation

Fixed planes: 2 orientations
Tilts/azimuths: 40 / 6.7 °
40 / 0 °

Sheds configuration

Models used

Transposition: Perez
Diffuse: Perez, Meteonorm
Circumsolar: separate

Horizon

Free Horizon

Near Shadings

Linear shadings : Fast (table)

User's needs

Monthly values

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
35.9	35.9	34.6	34.6	30.5	30.5	40.6	40.6	33.3	33.3	26.9	26.9	403	MWh/mth

PV Array Characteristics

Array #1 - PV Array

Orientation: #1
Tilt/Azimuth: 40/7 °

PV module

Manufacturer	Longi Solar
Model	LR5-72HPH-555M G2
(Original PVsyst database)	
Unit Nom. Power	555 Wp
Number of PV modules	306 units
Nominal (STC)	170 kWp
Modules	18 string x 17 In series
At operating cond. (50°C)	
Pmpp	156 kWp
U mpp	643 V
I mpp	242 A

Inverter

Manufacturer	SMA
Model	Sunny Tripower STP50-41-Core1
(Original PVsyst database)	
Unit Nom. Power	50.0 kWac
Number of inverters	3 units
Total power	150 kWac
Operating voltage	188-800 V
Pnom ratio (DC:AC)	1.13
Power sharing within this inverter	

Array #2 - Sub-array #2

Orientation: #2
Tilt/Azimuth: 40/0 °

PV module

Manufacturer	Longi Solar
Model	LR5-72HPH-550M G2
(Original PVsyst database)	
Unit Nom. Power	550 Wp
Number of PV modules	252 units
Nominal (STC)	139 kWp
Modules	14 string x 18 In series
At operating cond. (50°C)	
Pmpp	127 kWp
U mpp	680 V
I mpp	187 A

Inverter

Manufacturer	SMA
Model	Sunny Tripower STP62-US-41-Core1
(Original PVsyst database)	
Unit Nom. Power	62.5 kWac
Number of inverters	2 units
Total power	125 kWac
Operating voltage	150-800 V
Pnom ratio (DC:AC)	1.11
Power sharing within this inverter	

Total PV power

Nominal (STC)	308 kWp
Total	558 modules
Module area	1441 m²
Cell area	1338 m²

Total inverter power

Total power	275 kWac
Number of inverters	5 units
Pnom ratio	1.12

Array losses

Array Soiling Losses

Average loss Fraction 2.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	3.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%	3.0%

Thermal Loss factor

Module temperature according to irradiance

Uc (const) 29.0 W/m²K

Uv (wind) 0.0 W/m²K/m/s

Module Quality Loss

Loss Fraction -0.8 %

Module mismatch losses

Loss Fraction 2.0 % at MPP

IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

DC wiring losses

Global wiring resistance 10 mΩ

Loss Fraction 1.5 % at STC

Array #1 - PV Array

Global array res. 44 mΩ

Loss Fraction 1.5 % at STC

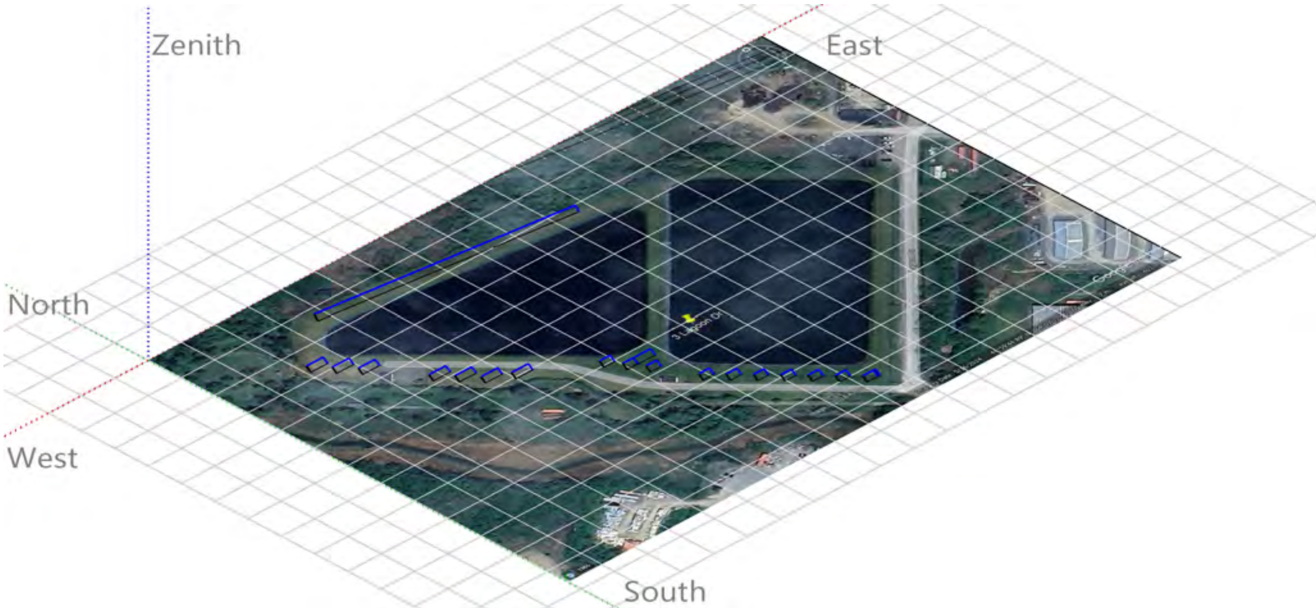
Array #2 - Sub-array #2

Global array res. 60 mΩ

Loss Fraction 1.5 % at STC

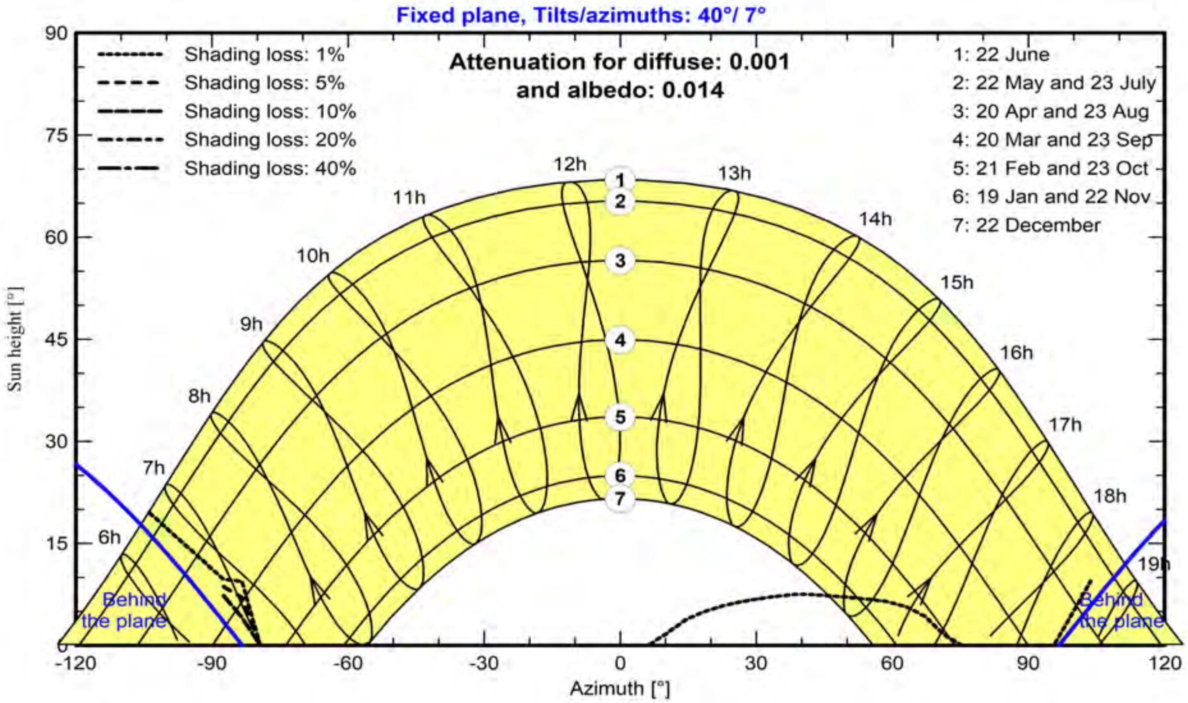
Near shadings parameter

Perspective of the PV-field and surrounding shading scene

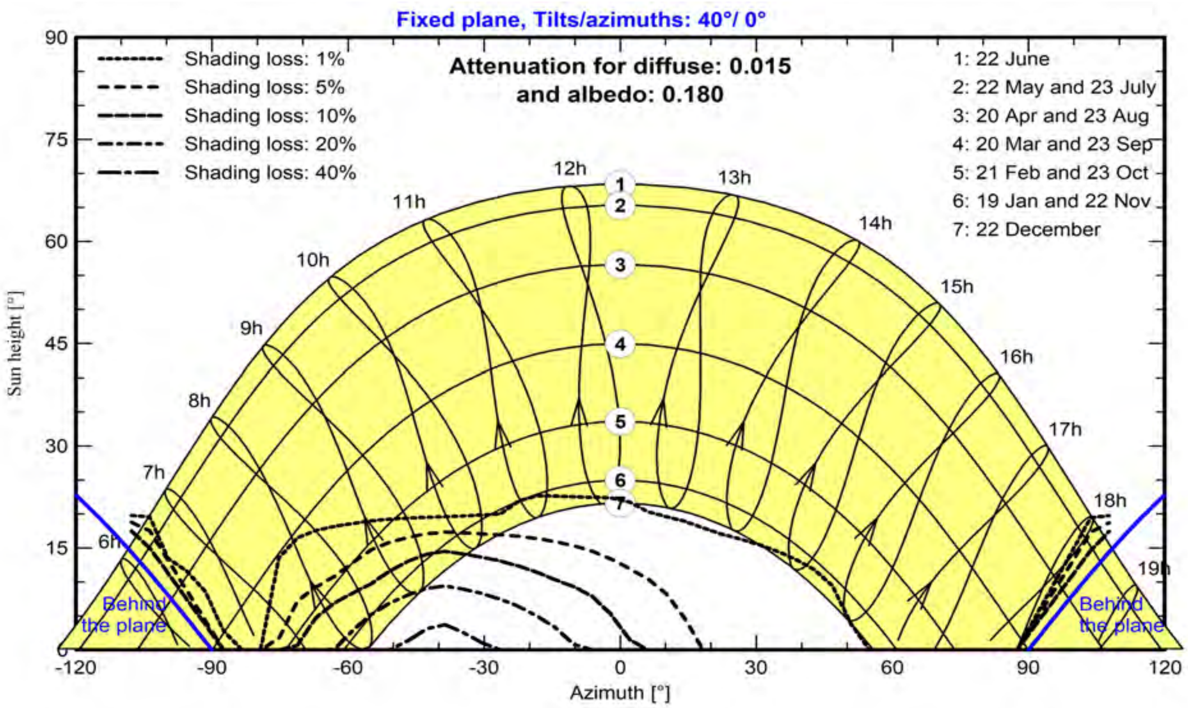


Iso-shadings diagram

Orientation #1



Orientation #2

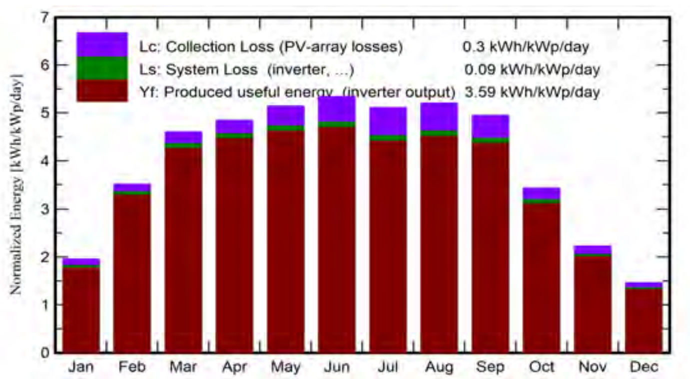


Main results

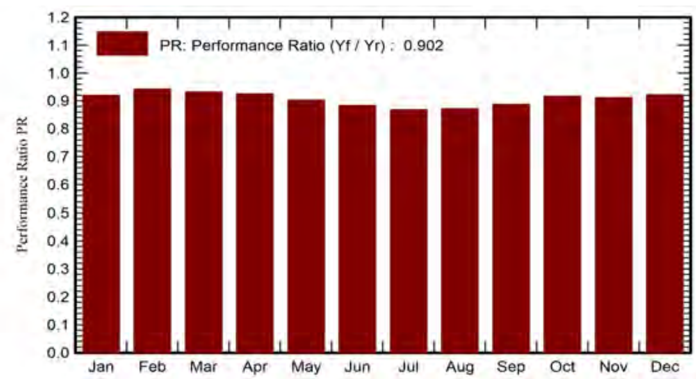
System Production

Produced Energy	404329 kWh/year	Specific production	1311 kWh/kWp/year
Used Energy	403298 kWh/year	Perf. Ratio PR	90.24 %
		Solar Fraction SF	37.99 %

Normalized productions (per installed kWp)



Performance Ratio PR



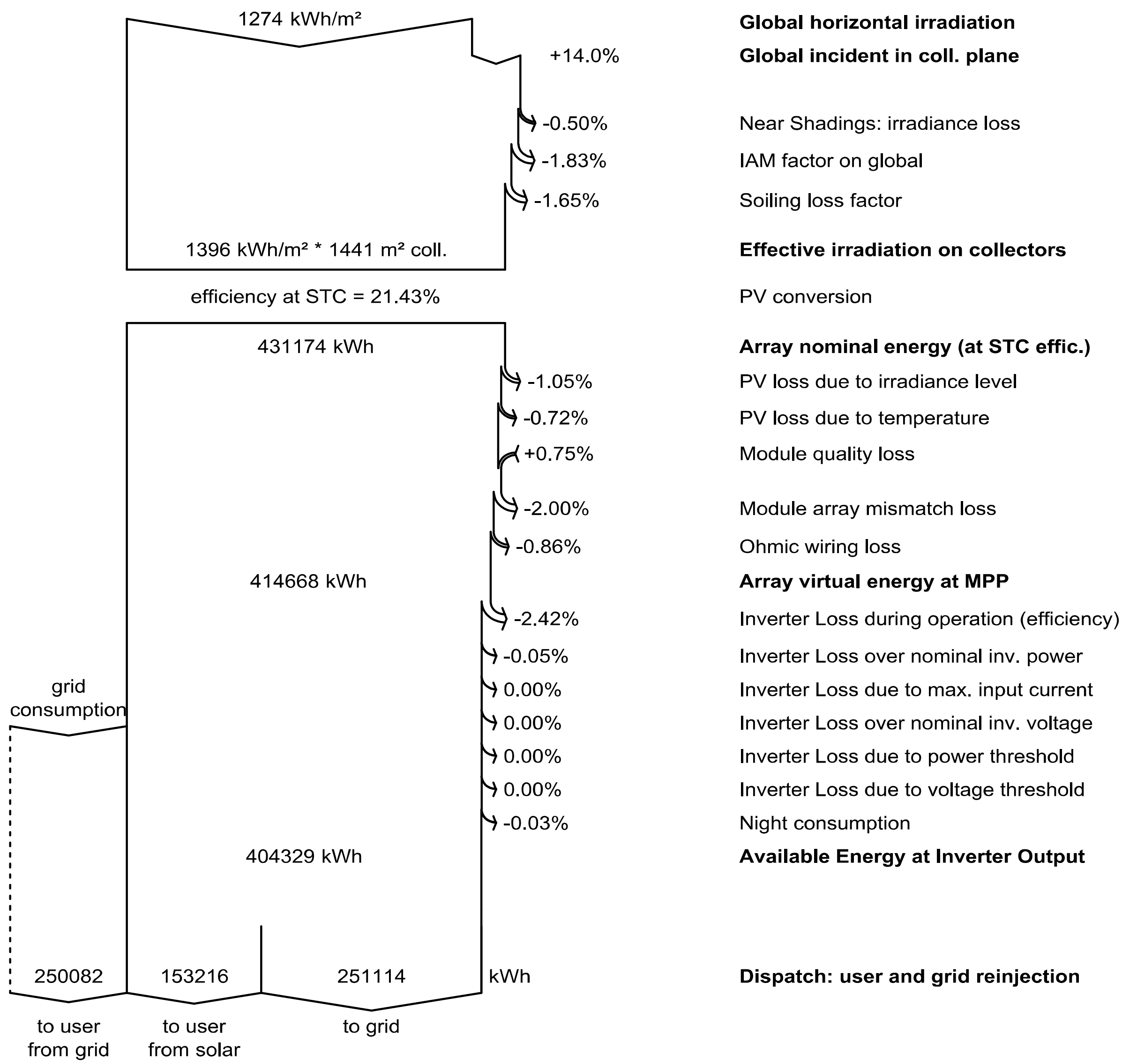
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.2	24.01	-4.97	60.7	56.2	17660	35863	8597	8613	27266
February	64.5	31.41	-4.64	98.2	93.7	29230	35863	11613	16922	24250
March	108.5	53.67	-0.79	142.6	135.7	41950	34575	13710	27249	20865
April	133.3	73.77	4.95	145.4	140.6	42515	34575	15266	26242	19309
May	165.6	88.54	10.92	159.3	153.4	45473	30474	14630	29744	15844
June	173.4	82.92	15.92	160.2	154.3	44754	30474	14668	28980	15806
July	168.6	80.95	20.62	158.4	152.7	43539	40574	18201	24245	22374
August	155.3	74.52	20.07	161.3	156.0	44466	40574	17691	25676	22883
September	120.0	50.73	15.56	148.3	143.7	41607	33294	13602	26983	19692
October	76.6	45.56	9.64	106.2	103.0	30764	33293	11896	18143	21398
November	41.0	23.90	4.03	66.9	63.5	19281	26869	6768	12019	20101
December	29.7	22.55	-1.19	45.2	42.6	13226	26869	6574	6299	20295
Year	1273.7	652.53	7.58	1452.6	1395.5	414466	403298	153216	251114	250082

Legends

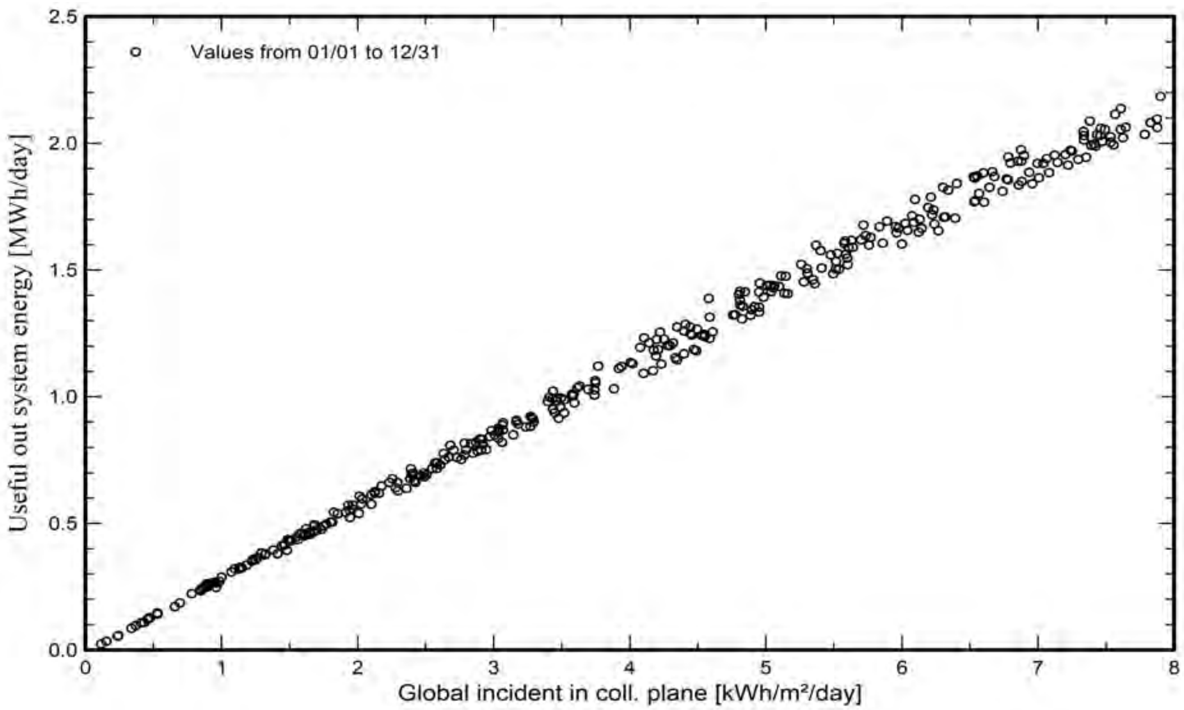
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

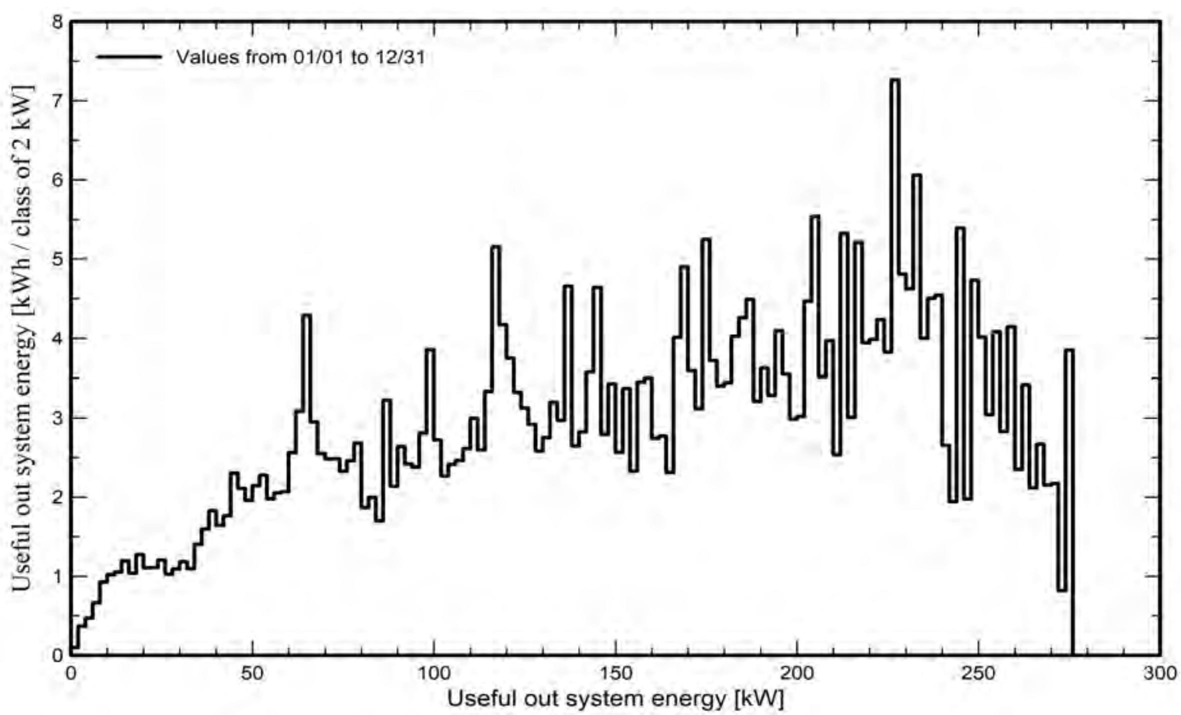


Predef. graphs

Daily Input/Output diagram

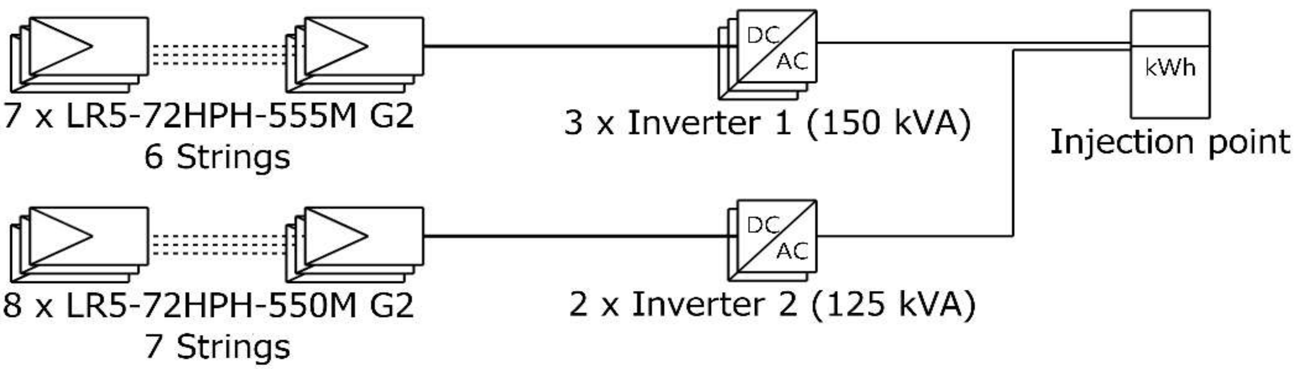


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC2, Simulation date:
08/15/24 13:29
with V7.4.8



PV module 1	LR5-72HPH-555M G2
PV module 2	LR5-72HPH-550M G2
Inverter 1	Sunny Tripower STP50-41-Core1
Inverter 2	Sunny Tripower STP62-US-41-Core1
String 1	17 x LR5-72HPH-555M G2
String 2	18 x LR5-72HPH-550M G2

	3 Lagoon Dr	CBCL Limited (Canada)
	VC2 : 3 Lagoon Dr 308 kw MONO-2	08/15/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 3 Lagoon Dr

Variant: 3 Lagoon Dr 297 kw BIFACIAL

Sheds on ground

System power: 297 kWp

Windsor - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site	Situation		Project settings	
Windsor	Latitude	44.99 °N	Albedo	0.20
Canada	Longitude	-64.15 °W		
	Altitude	14 m		
	Time zone	UTC-4		

Weather data
Windsor
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System

Sheds on ground

PV Field Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

System information

PV Array		Inverters	
Nb. of modules	540 units	Nb. of units	5 units
Pnom total	297 kWp	Pnom total	275 kWac
		Pnom ratio	1.080

Results summary

Produced Energy	420771 kWh/year	Specific production	1417 kWh/kWp/year	Perf. Ratio PR	97.45 %
Used Energy	403298 kWh/year			Solar Fraction SF	38.89 %

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General parameters

Grid-Connected System

Sheds on ground

PV Field Orientation

Orientation

Fixed plane
Tilt/Azimuth 40 / 0 °

Sheds configuration

Nb. of sheds 20 units

Sizes

Sheds spacing 10.5 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 43.6 %
Top inactive band 0.02 m
Bottom inactive band 0.02 m

Shading limit angle

Limit profile angle 22.9 °

Models used

Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon

Free Horizon

Near Shadings

Linear shadings : Fast (table)

User's needs

Monthly values

Bifacial system

Model 2D Calculation
unlimited sheds

Bifacial model geometry

Sheds spacing	10.50 m
Sheds width	4.62 m
Limit profile angle	22.9 °
GCR	44.0 %
Height above ground	1.50 m

Bifacial model definitions

Ground albedo	0.30
Bifaciality factor	70 %
Rear shading factor	5.0 %
Rear mismatch loss	10.0 %
Shed transparent fraction	0.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
35.9	35.9	34.6	34.6	30.5	30.5	40.6	40.6	33.3	33.3	26.9	26.9	403	MWh/mth

PV Array Characteristics

Array #1 - PV Array

PV module

Manufacturer	Longi Solar
Model	LR5-72HBD-550M G2 Bifacial
(Original PVsyst database)	
Unit Nom. Power	550 Wp
Number of PV modules	288 units
Nominal (STC)	158 kWp
Modules	16 string x 18 In series
At operating cond. (50°C)	
Pmpp	145 kWp
U mpp	680 V
I mpp	213 A

Inverter

Manufacturer	SMA
Model	Sunny Tripower STP50-41-Core1
(Original PVsyst database)	
Unit Nom. Power	50.0 kWac
Number of inverters	3 units
Total power	150 kWac
Operating voltage	188-800 V
Pnom ratio (DC:AC)	1.06
Power sharing within this inverter	

PV Array Characteristics

Array #2 - Sub-array #2

PV module

Manufacturer	Longi Solar
Model	LR5-72HBD-550M G2 Bifacial
(Original PVsyst database)	
Unit Nom. Power	550 Wp
Number of PV modules	252 units
Nominal (STC)	139 kWp
Modules	14 string x 18 In series
At operating cond. (50°C)	
Pmpp	127 kWp
U mpp	680 V
I mpp	187 A

Inverter

Manufacturer	SMA
Model	Sunny Tripower STP62-US-41-Core1
(Original PVsyst database)	
Unit Nom. Power	62.5 kWac
Number of inverters	2 units
Total power	125 kWac
Operating voltage	150-800 V
Pnom ratio (DC:AC)	1.11
Power sharing within this inverter	

Total PV power

Nominal (STC)	297 kWp
Total	540 modules
Module area	1395 m²
Cell area	1295 m²

Total inverter power

Total power	275 kWac
Number of inverters	5 units
Pnom ratio	1.08

Array losses

Array Soiling Losses
Average loss Fraction 2.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	3.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%	3.0%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

Module Quality Loss
Loss Fraction -0.8 %

Module mismatch losses
Loss Fraction 2.0 % at MPP

IAM loss factor
Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

DC wiring losses

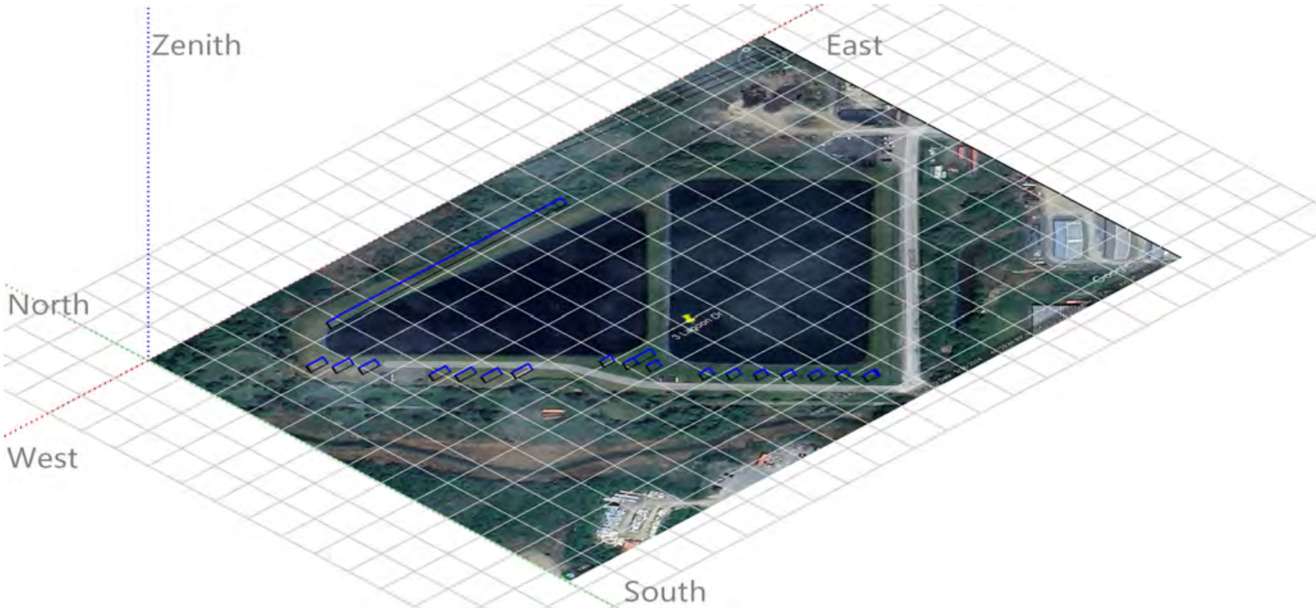
Global wiring resistance 10 mΩ
Loss Fraction 1.5 % at STC

Array #1 - PV Array
Global array res. 53 mΩ
Loss Fraction 1.5 % at STC

Array #2 - Sub-array #2
Global array res. 60 mΩ
Loss Fraction 1.5 % at STC

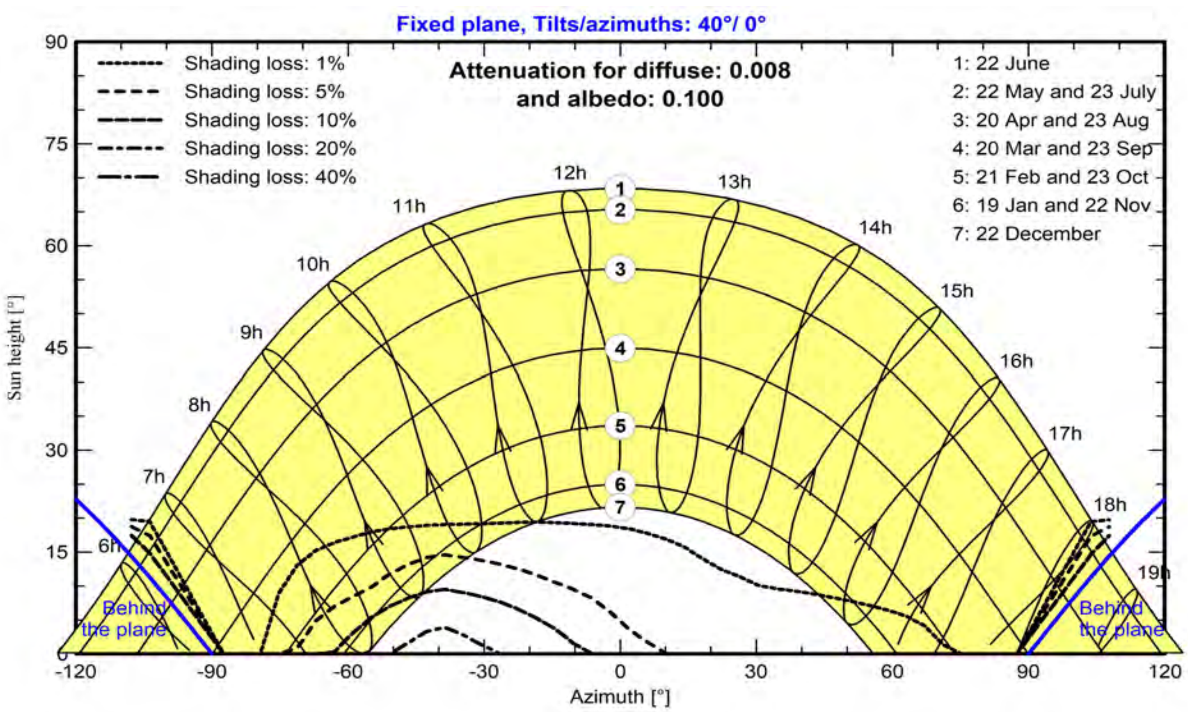
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

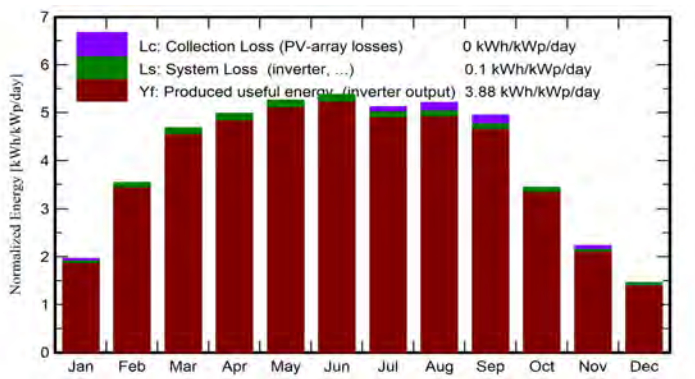


Main results

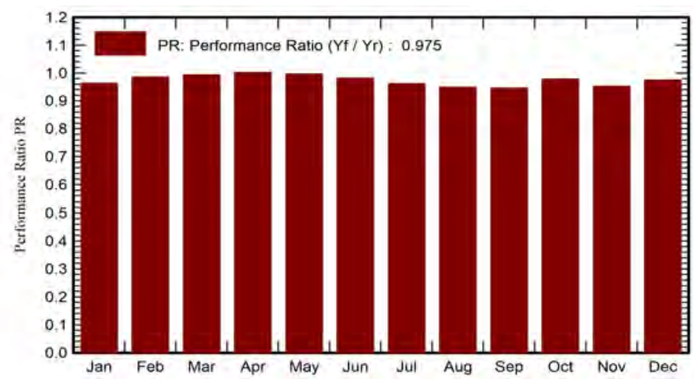
System Production

Produced Energy	420771 kWh/year	Specific production	1417 kWh/kWp/year
Used Energy	403298 kWh/year	Perf. Ratio PR	97.45 %
		Solar Fraction SF	38.89 %

Normalized productions (per installed kWp)



Performance Ratio PR



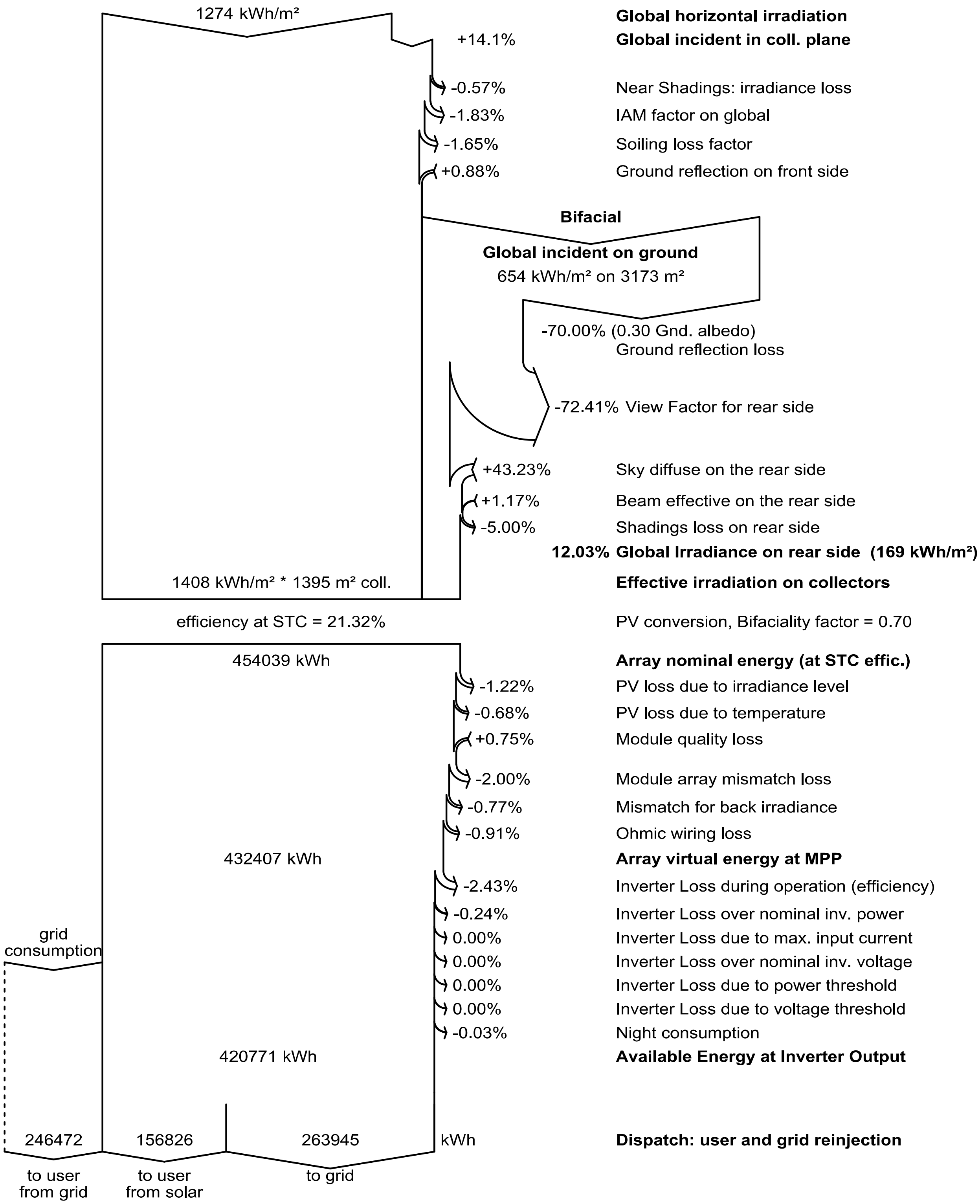
Balances and main results

	GlobHor	DiffHor	T_Amb	GlobInc	GlobEff	EArray	E_User	E_Solar	E_Grid	EFrGrid
	kWh/m²	kWh/m²	°C	kWh/m²	kWh/m²	kWh	kWh	kWh	kWh	kWh
January	37.2	24.01	-4.97	60.7	56.4	17831	35863	8802	8569	27062
February	64.5	31.41	-4.64	98.1	94.0	29409	35863	11738	16959	24125
March	108.5	53.67	-0.79	142.6	136.5	43116	34575	13861	28216	20714
April	133.3	73.77	4.95	145.5	141.9	44375	34575	15493	27811	19082
May	165.6	88.54	10.92	159.5	155.4	48399	30474	15181	32035	15293
June	173.4	82.92	15.92	160.3	156.4	47927	30474	15375	31369	15099
July	168.6	80.95	20.62	158.7	154.9	46481	40574	18876	26451	21699
August	155.3	74.52	20.07	161.4	157.6	46639	40574	18111	27381	22463
September	120.0	50.73	15.56	148.3	144.5	42692	33294	13694	27945	19599
October	76.6	45.56	9.64	106.3	103.7	31644	33293	12047	18836	21247
November	41.0	23.90	4.03	66.9	63.8	19434	26869	6921	12007	19948
December	29.7	22.55	-1.19	45.2	42.8	13460	26869	6728	6367	20141
Year	1273.7	652.53	7.58	1453.7	1407.8	431406	403298	156826	263945	246472

Legends

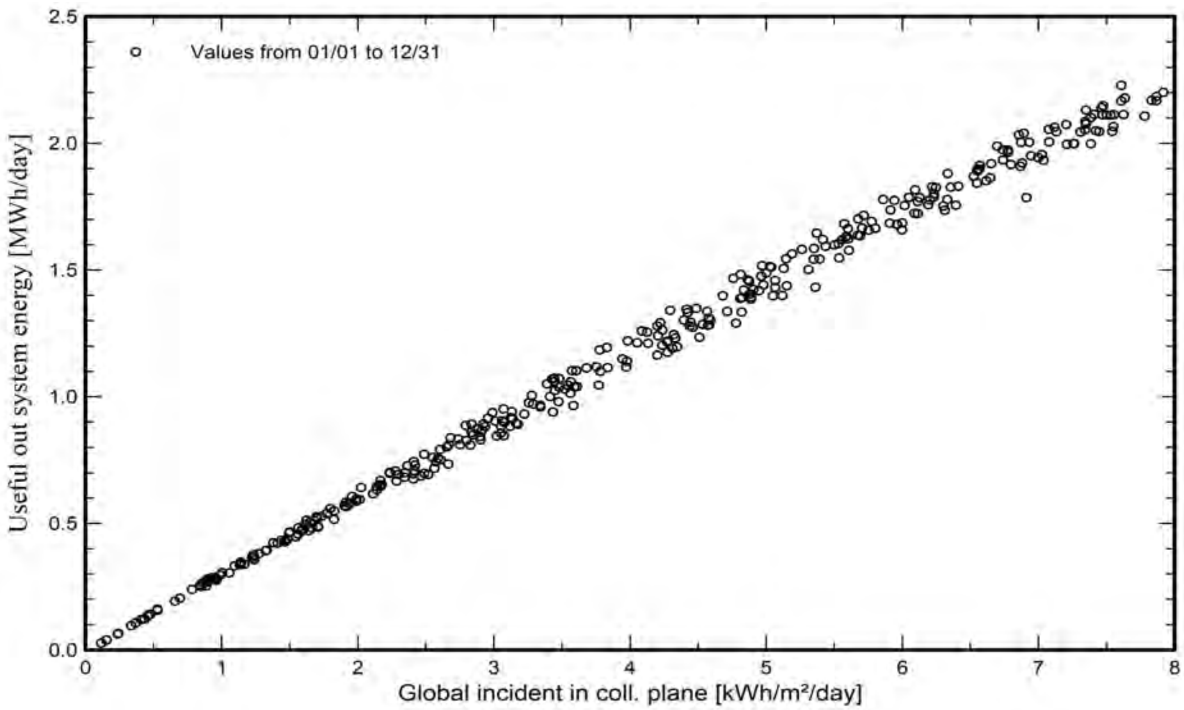
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

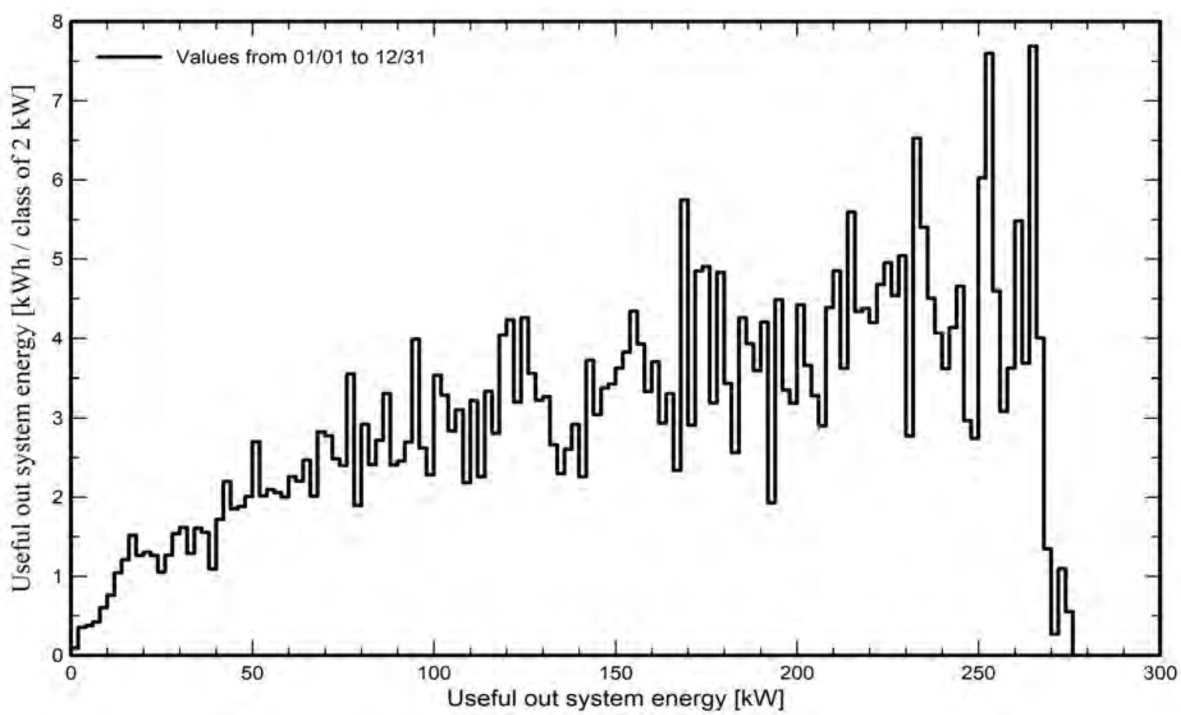


Predef. graphs

Daily Input/Output diagram



System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC1, Simulation date:
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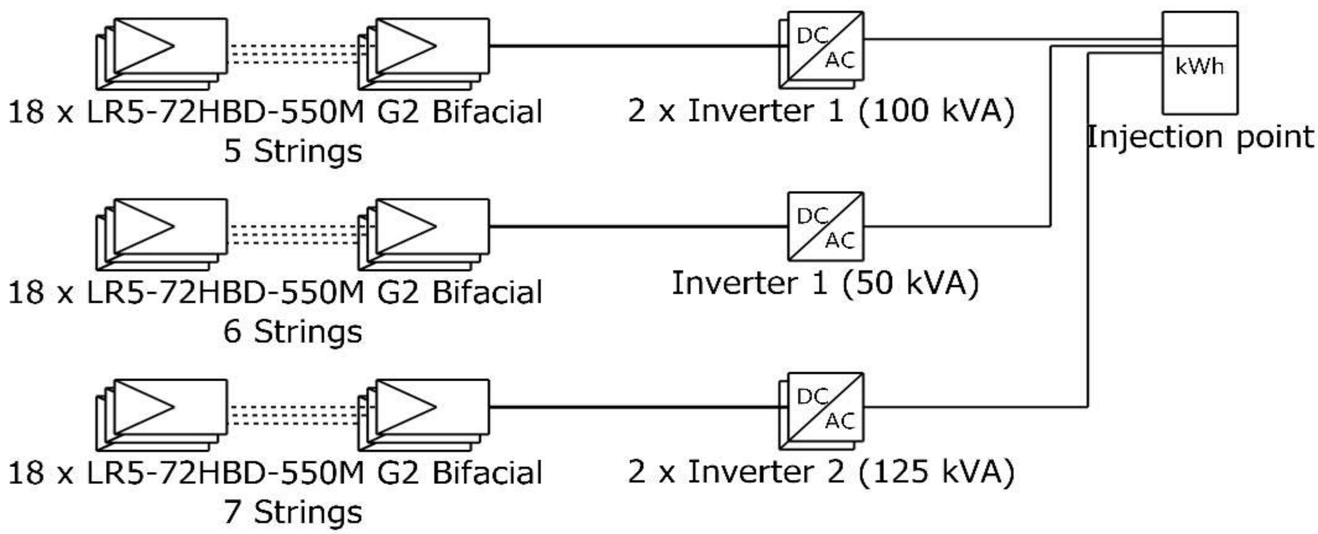
with V7.4.8



PV module	LR5-72HBD-550M G2 Bifacial
Inverter 1	Sunny Tripower STP50-41-Core1
Inverter 2	Sunny Tripower STP62-US-41-Core1
String	18 x LR5-72HBD-550M G2 Bifacial

	3 Lagoon Dr	CBCL Limited (Canada)
	VC1 : 3 Lagoon Dr 297 kw BIFACIAL	08/12/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 3 Lagoon Dr

Variant: 3 Lagoon Dr 279 kw BIFACIAL

Sheds on ground

System power: 279 kWp

Windsor - Canada

Author

CBCL Limited (Canada)

Project summary

Geographical Site
Windsor
Canada

Situation

Latitude	44.99 °N
Longitude	-64.15 °W
Altitude	14 m
Time zone	UTC-4

Project settings

Albedo	0.20

Weather data
Windsor
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System

Sheds on ground

PV Field Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

System information

PV Array		Inverters	
Nb. of modules	508 units	Nb. of units	4 units
Pnom total	279 kWp	Pnom total	250 kWac
		Pnom ratio	1.118

Results summary

Produced Energy	395465 kWh/year	Specific production	1415 kWh/kWp/year	Perf. Ratio PR	97.36 %
Used Energy	403298 kWh/year			Solar Fraction SF	38.48 %

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General parameters

Grid-Connected System — **Sheds on ground**

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 40 / 0 °

Sheds configuration
Nb. of sheds 20 units

Sizes
Sheds spacing 10.5 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 43.6 %
Top inactive band 0.02 m
Bottom inactive band 0.02 m

Shading limit angle
Limit profile angle 22.9 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Free Horizon

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Bifacial system
Model 2D Calculation
unlimited sheds

Bifacial model geometry
Sheds spacing 10.50 m
Sheds width 4.62 m
Limit profile angle 22.9 °
GCR 44.0 %
Height above ground 1.50 m

Bifacial model definitions
Ground albedo 0.30
Bifaciality factor 70 %
Rear shading factor 5.0 %
Rear mismatch loss 10.0 %
Shed transparent fraction 0.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
35.9	35.9	34.6	34.6	30.5	30.5	40.6	40.6	33.3	33.3	26.9	26.9	403	MWh/mth

PV Array Characteristics

PV module
Manufacturer Longi Solar
Model LR5-72HBD-550M G2 Bifacial
(Original PVsyst database)
Unit Nom. Power 550 Wp
Number of PV modules 508 units
Nominal (STC) 279 kWp

Inverter
Manufacturer SMA
Model Sunny Tripower STP62-US-41-Core1
(Original PVsyst database)
Unit Nom. Power 62.5 kWac
Number of inverters 4 units
Total power 250 kWac

Array #1 - PV Array
Number of PV modules 256 units
Nominal (STC) 141 kWp
Modules 16 string x 16 In series

At operating cond. (50°C)
Pmpp 129 kWp
U mpp 604 V
I mpp 213 A

Number of inverters 2 units
Total power 125 kWac
Operating voltage 150-800 V
Pnom ratio (DC:AC) 1.13
Power sharing within this inverter

Array #2 - Sub-array #2
Number of PV modules 252 units
Nominal (STC) 139 kWp
Modules 14 string x 18 In series

Number of inverters 2 units
Total power 125 kWac

PV Array Characteristics

Array #2 - Sub-array #2

At operating cond. (50°C)

Pmpp	127 kWp	Operating voltage	150-800 V
U mpp	680 V	Pnom ratio (DC:AC)	1.11
I mpp	187 A	Power sharing within this inverter	

Total PV power

Nominal (STC)	279 kWp
Total	508 modules
Module area	1312 m²
Cell area	1218 m²

Total inverter power

Total power	250 kWac
Number of inverters	4 units
Pnom ratio	1.12

Array losses

Array Soiling Losses

Average loss Fraction 2.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	3.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%	3.0%

Thermal Loss factor

Module temperature according to irradiance

Uc (const) 29.0 W/m²K

Uv (wind) 0.0 W/m²K/m/s

Module Quality Loss

Loss Fraction -0.8 %

Module mismatch losses

Loss Fraction 2.0 % at MPP

IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

DC wiring losses

Global wiring resistance 10 mΩ

Loss Fraction 1.5 % at STC

Array #1 - PV Array

Global array res. 47 mΩ

Loss Fraction 1.5 % at STC

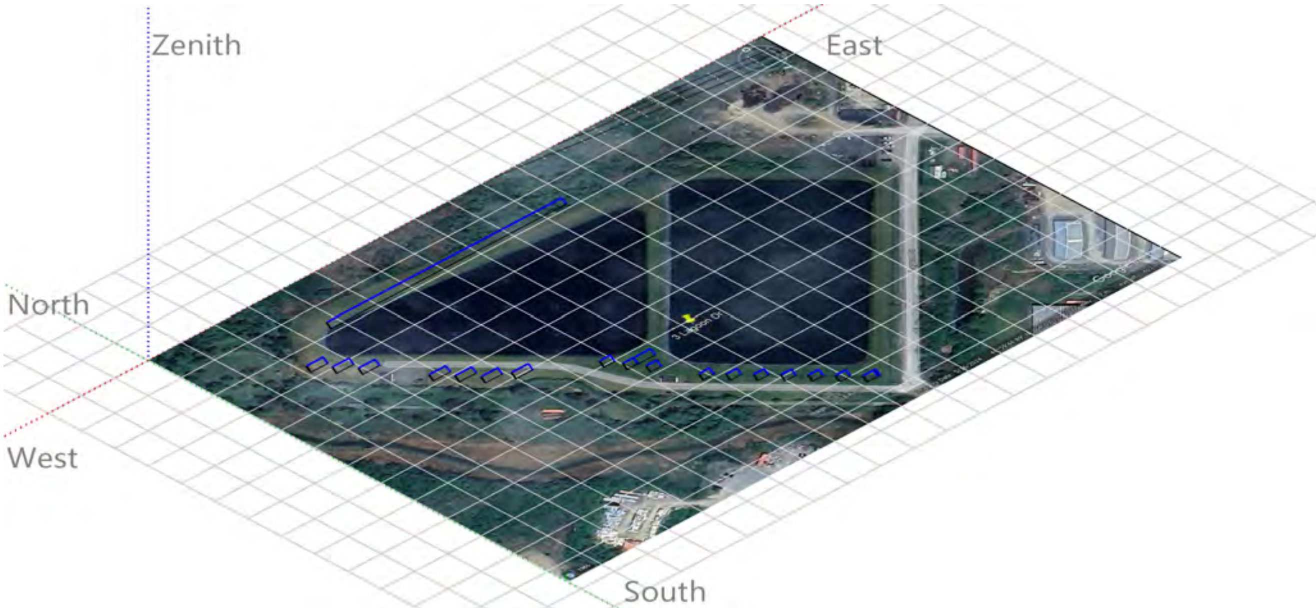
Array #2 - Sub-array #2

Global array res. 60 mΩ

Loss Fraction 1.5 % at STC

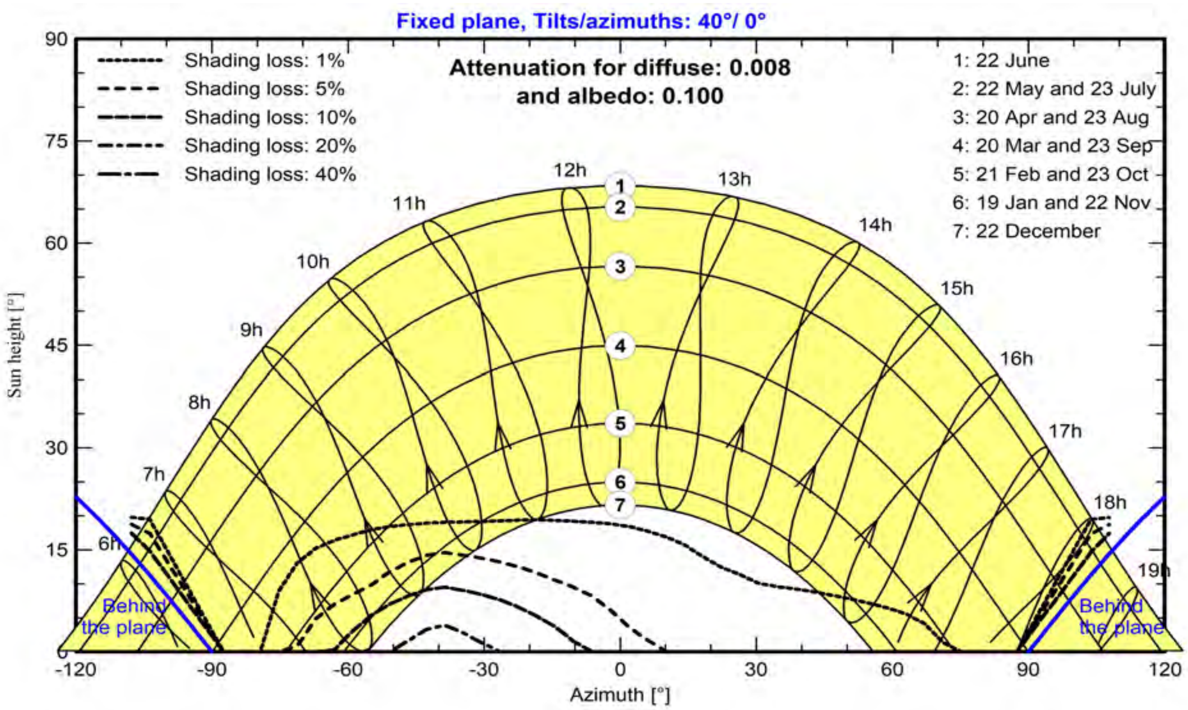
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

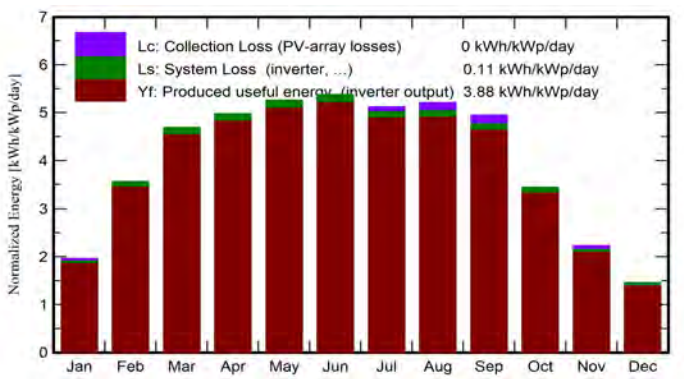


Main results

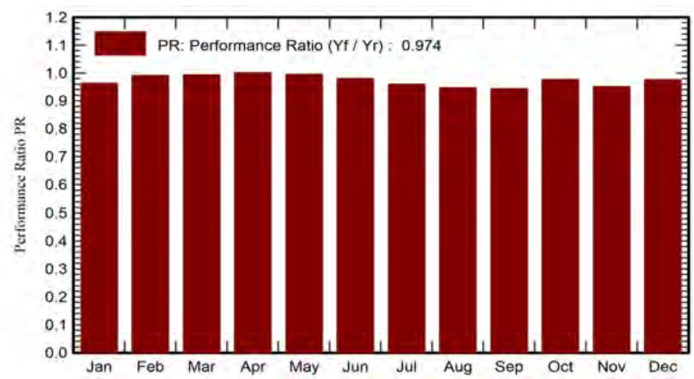
System Production

Produced Energy	395465 kWh/year	Specific production	1415 kWh/kWp/year
Used Energy	403298 kWh/year	Perf. Ratio PR	97.36 %
		Solar Fraction SF	38.48 %

Normalized productions (per installed kWp)



Performance Ratio PR



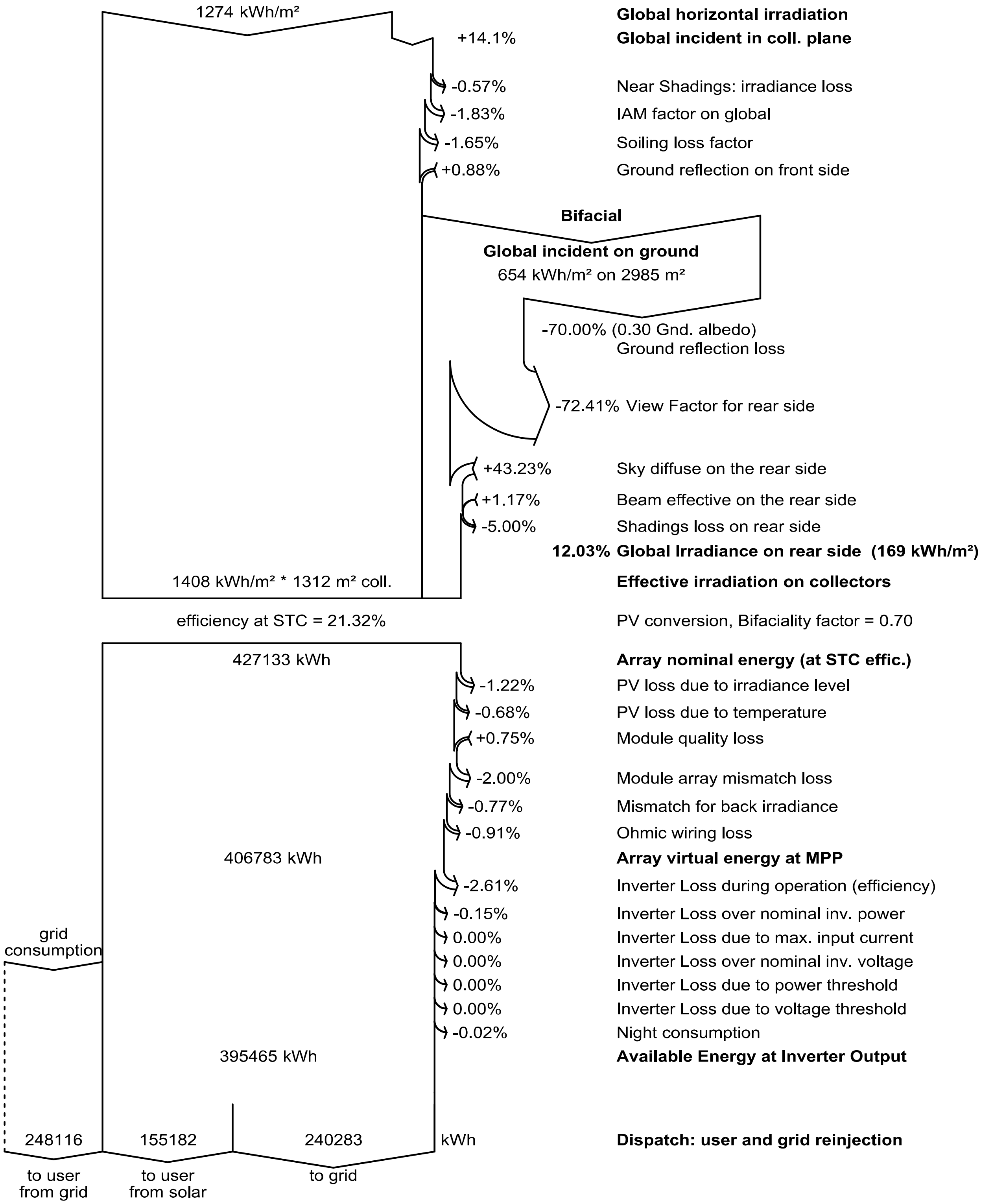
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.2	24.01	-4.97	60.7	56.4	16777	35863	8649	7694	27214
February	64.5	31.41	-4.64	98.1	94.0	27855	35863	11631	15530	24232
March	108.5	53.67	-0.79	142.6	136.5	40596	34575	13734	25834	20840
April	133.3	73.77	4.95	145.5	141.9	41740	34575	15377	25295	19198
May	165.6	88.54	10.92	159.5	155.4	45539	30474	15045	29296	15429
June	173.4	82.92	15.92	160.3	156.4	45104	30474	15208	28681	15266
July	168.6	80.95	20.62	158.7	154.9	43762	40574	18665	23900	21909
August	155.3	74.52	20.07	161.4	157.6	43905	40574	17905	24806	22669
September	120.0	50.73	15.56	148.3	144.5	40179	33294	13584	25511	19709
October	76.6	45.56	9.64	106.3	103.7	29772	33293	11929	17078	21364
November	41.0	23.90	4.03	66.9	63.8	18282	26869	6830	10959	20039
December	29.7	22.55	-1.19	45.2	42.8	12662	26869	6624	5699	20245
Year	1273.7	652.53	7.58	1453.7	1407.8	406174	403298	155182	240283	248116

Legends

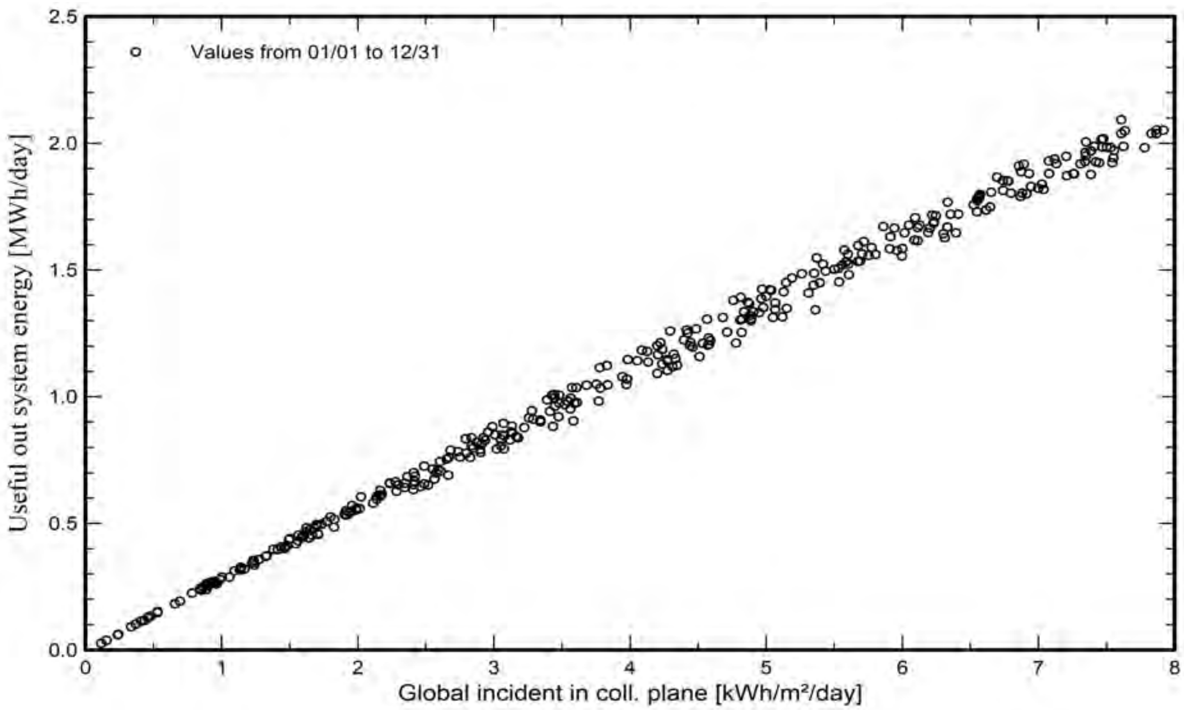
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

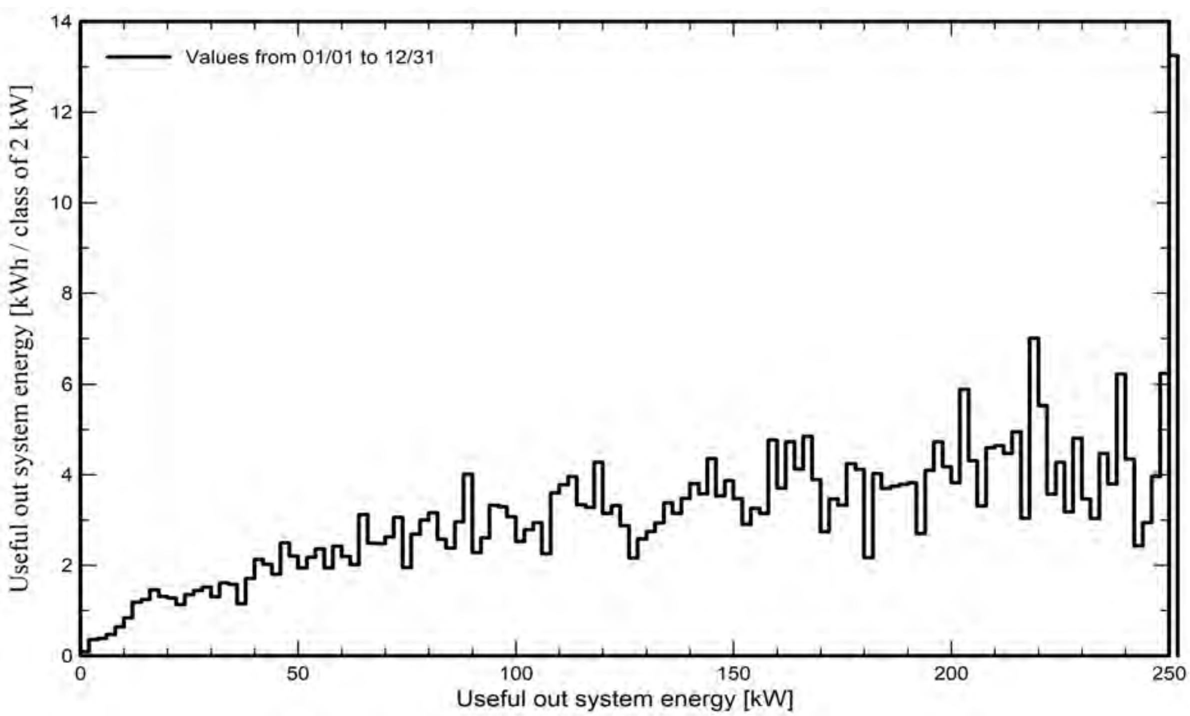


Predef. graphs

Daily Input/Output diagram

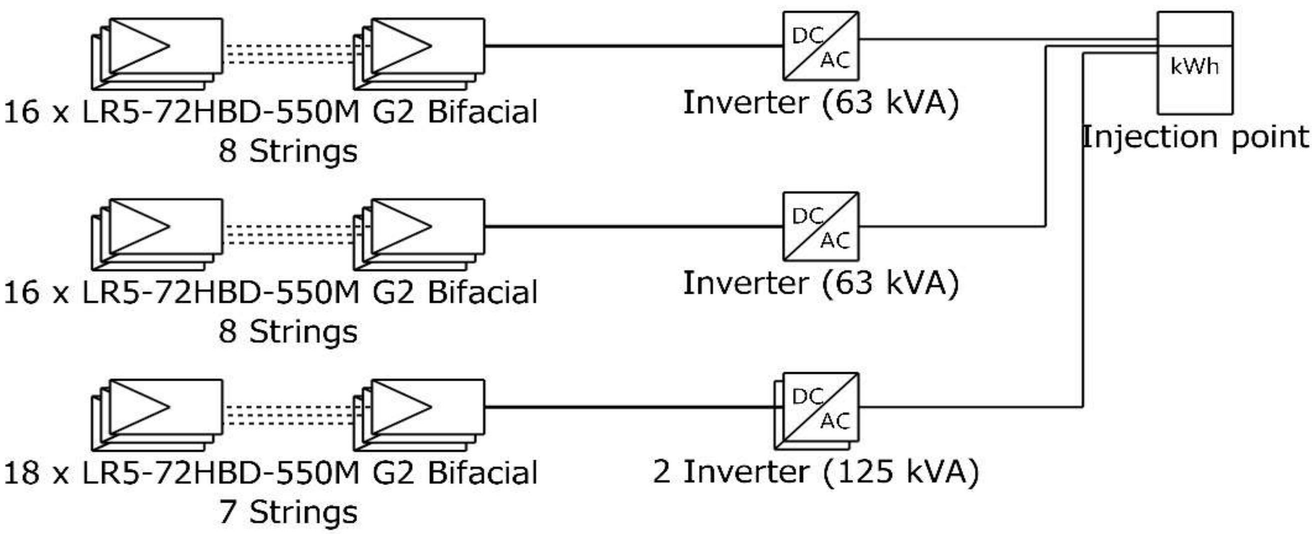


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC1, Simulation date:
08/16/24 16:28
with V7.4.8



PV module	LR5-72HBD-550M G2 Bifacial
Inverter	Sunny Tripower STP62-US-41-Core1
String 1	16 x LR5-72HBD-550M G2 Bifacial
String 2	18 x LR5-72HBD-550M G2 Bifacial

3 Lagoon Dr	CBCL Limited (Canada)
VC1 : 3 Lagoon Dr 279 kw BIFACIAL	08/16/24

PVsyst - Simulation report

Grid-Connected System

Project: 786 Windsor Back Road:Windsor Water Treatment Plant

Variant: Windsor Water Treatment Plant 64.9 kW ground & roof MONO

Sheds on a building

System power: 64.9 kWp

786 Windsor Back Rd: Windsor WTP - Canada

Author

CBCL Limited (Canada)

Project: 786 Windsor Back Road:Windsor Water Treatment Plant

Variant: Windsor Water Treatment Plant 64.9 kW ground & roof MONO

CBCL Limited (Canada)

Project summary

Geographical Site
786 Windsor Back Rd: Windsor WTP
Canada

Situation

Latitude	44.96 °N
Longitude	-64.12 °W
Altitude	14 m
Time zone	UTC-4

Project settings

Albedo	0.20

Weather data
786 Windsor Back Rd: Windsor WTP
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System

Sheds on a building

PV Field Orientation

Fixed planes	2 orientations
Tilts/azimuths	30 / -43 °
	10 / 18.6 °

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

System information

PV Array

Nb. of modules	117 units
Pnom total	64.9 kWp

Inverters

Nb. of units	3 units
Pnom total	60.3 kWac
Pnom ratio	1.077

Results summary

Produced Energy	75019 kWh/year	Specific production	1155 kWh/kWp/year	Perf. Ratio PR	83.82 %
Used Energy	336894 kWh/year			Solar Fraction SF	20.80 %

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General parameters

Grid-Connected System

Sheds on a building

PV Field Orientation

Orientation

Fixed planes	2 orientations
Tilts/azimuths	30 / -43 °
	10 / 18.6 °

Sheds configuration

Models used

Transposition	Perez
Diffuse	Perez, Meteonorm
Circumsolar	separate

Horizon

Average Height 6.8 °

Near Shadings

Linear shadings : Fast (table)

User's needs

Monthly values

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
35.8	31.5	34.9	27.7	28.1	27.1	23.8	24.0	22.3	25.8	26.9	29.1	337	MWh

PV Array Characteristics

PV module

Manufacturer	Longi Solar
Model	LR5-72HPH-555M G2
(Original PVsyst database)	
Unit Nom. Power	555 Wp
Number of PV modules	117 units
Nominal (STC)	64.9 kWp

Inverter

Manufacturer	SMA
Model	Sunny Tripower X - STP20-US-50
(Original PVsyst database)	
Unit Nom. Power	20.1 kWac
Number of inverters	3 units
Total power	60.3 kWac

Array #1 - PV Array

Orientation	#1		
Tilt/Azimuth	30/-43 °		
Number of PV modules	45 units	Number of inverters	1 unit
Nominal (STC)	24.98 kWp	Total power	20.1 kWac
Modules	3 string x 15 In series		
At operating cond. (50°C)		Operating voltage	150-1000 V
Pmpp	22.89 kWp	Pnom ratio (DC:AC)	1.24
U mpp	568 V	Power sharing within this inverter	
I mpp	40 A		

Array #2 - Sub-array #2

Orientation	#2		
Tilt/Azimuth	10/19 °		
Number of PV modules	72 units	Number of inverters	2 units
Nominal (STC)	40.0 kWp	Total power	40.2 kWac
Modules	4 string x 18 In series		
At operating cond. (50°C)		Operating voltage	150-1000 V
Pmpp	36.6 kWp	Pnom ratio (DC:AC)	0.99
U mpp	681 V	Power sharing within this inverter	
I mpp	54 A		

Total PV power

Nominal (STC)	65 kWp
Total	117 modules
Module area	302 m²
Cell area	281 m²

Total inverter power

Total power	60.3 kWac
Number of inverters	3 units
Pnom ratio	1.08

Array losses

Array Soiling Losses

Average loss Fraction 2.2 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
6.0%	5.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	2.0%	3.0%

Thermal Loss factor

Module temperature according to irradiance
Uc (const) 20.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

Module Quality Loss

Loss Fraction -0.8 %

Module mismatch losses

Loss Fraction 2.0 % at MPP

IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

DC wiring losses

Global wiring resistance 10 mΩ
Loss Fraction 1.5 % at STC

Array #1 - PV Array

Global array res. 233 mΩ
Loss Fraction 1.5 % at STC

Array #2 - Sub-array #2

Global array res. 210 mΩ
Loss Fraction 1.5 % at STC

Horizon definition

Horizon line at 786 Windsor Back Rd: Windsor WTP

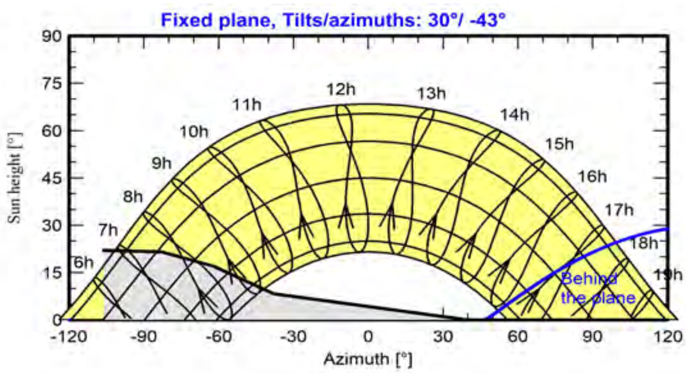
Average Height	6.8 °	Albedo Factor	0.85
Diffuse Factor	0.98	Albedo Fraction	100 %

Horizon profile

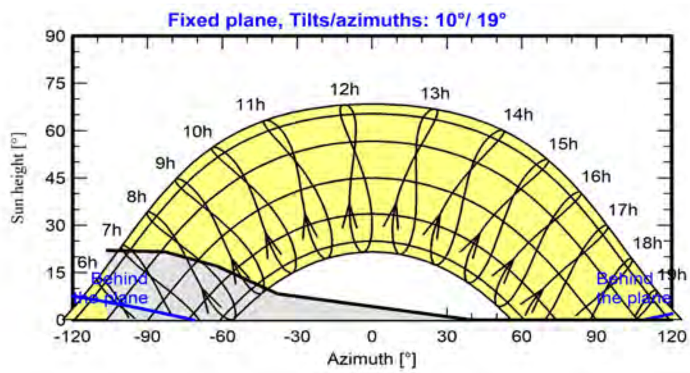
Azimuth [°]	-106	-83	-62	-38	40	120
Height [°]	22.1	21.6	17.0	8.3	0.0	0.0

Sun Paths (Height / Azimuth diagram)

Orientation #1

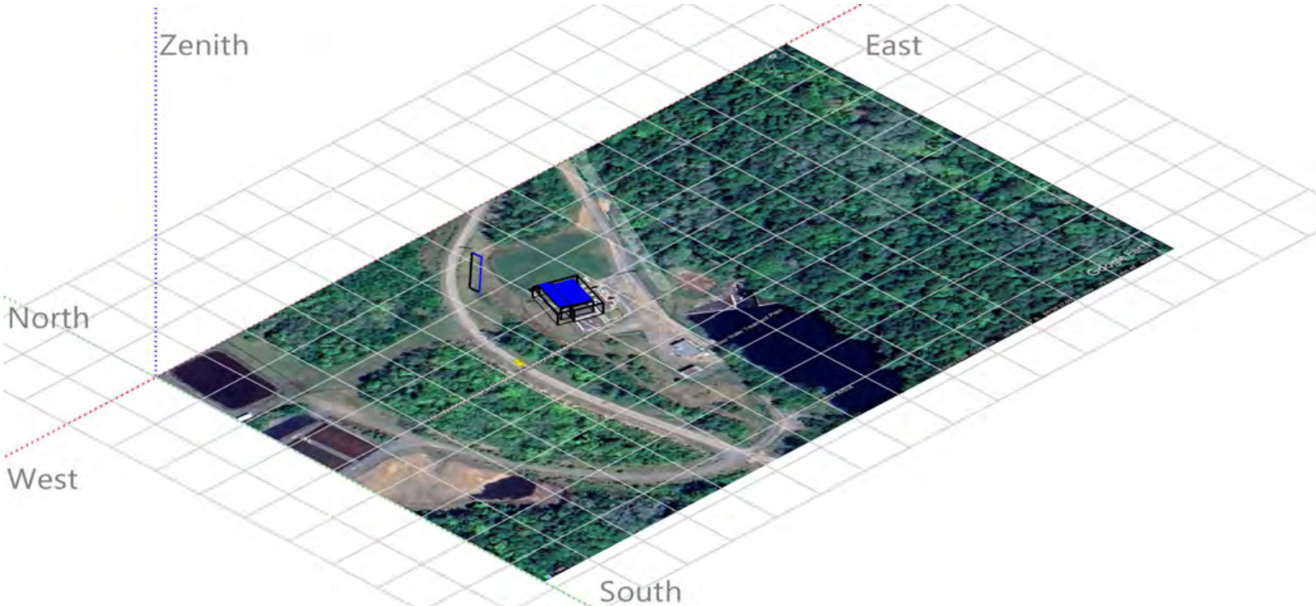


Orientation #2



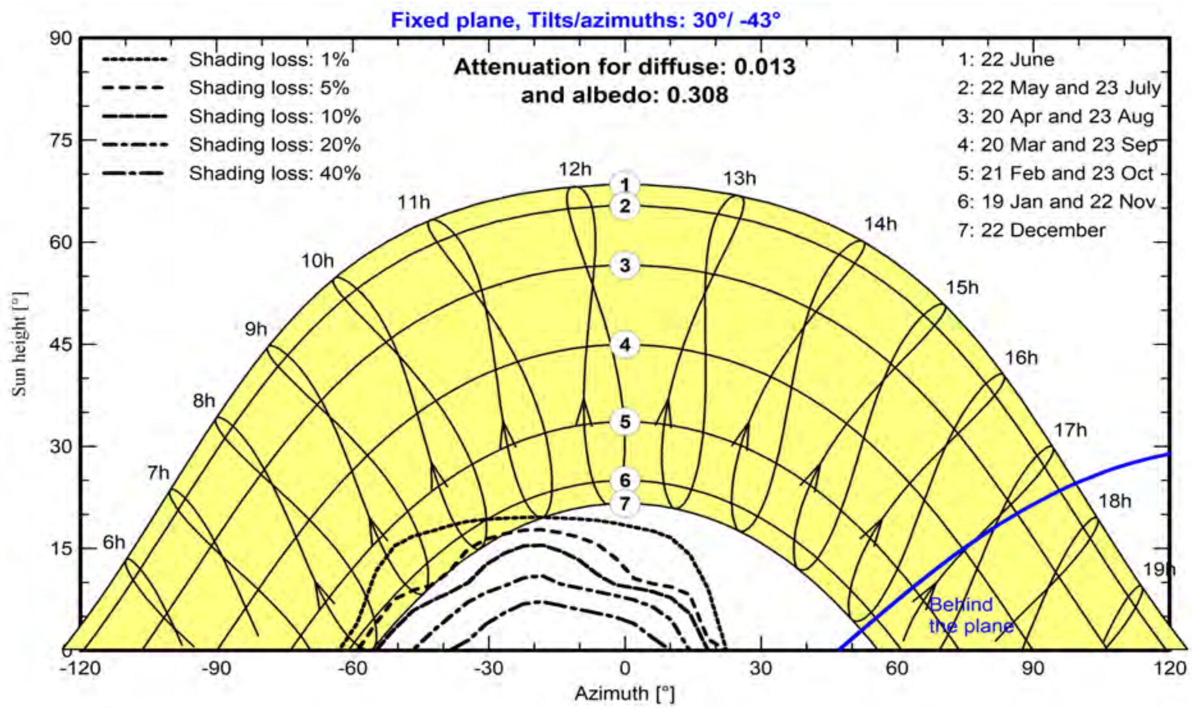
Near shadings parameter

Perspective of the PV-field and surrounding shading scene

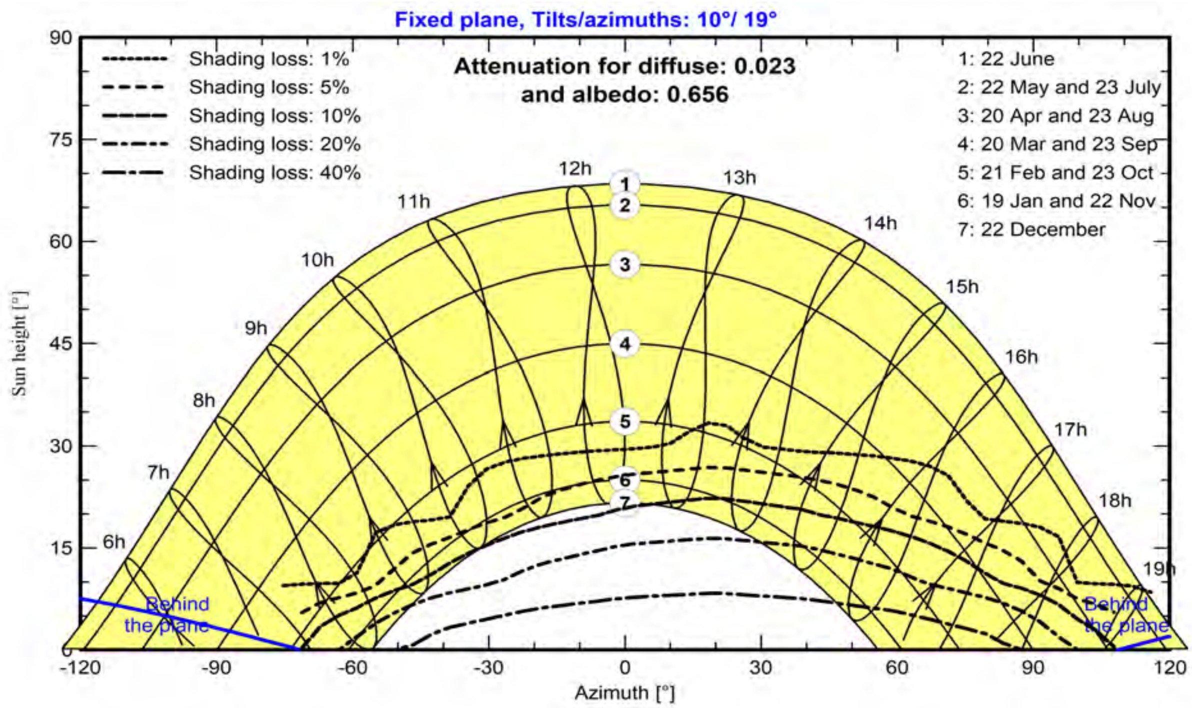


Iso-shadings diagram

Orientation #1



Orientation #2

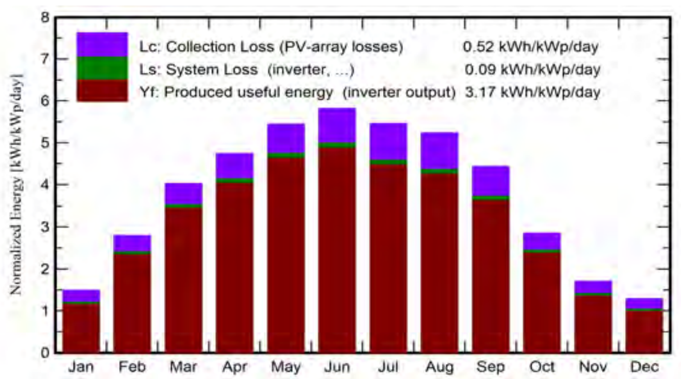


Main results

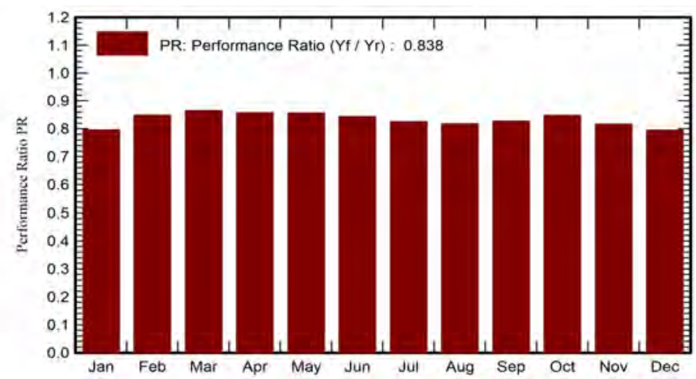
System Production

Produced Energy	75019 kWh/year	Specific production	1155 kWh/kWp/year
Used Energy	336894 kWh/year	Perf. Ratio PR	83.82 %
		Solar Fraction SF	20.80 %

Normalized productions (per installed kWp)



Performance Ratio PR



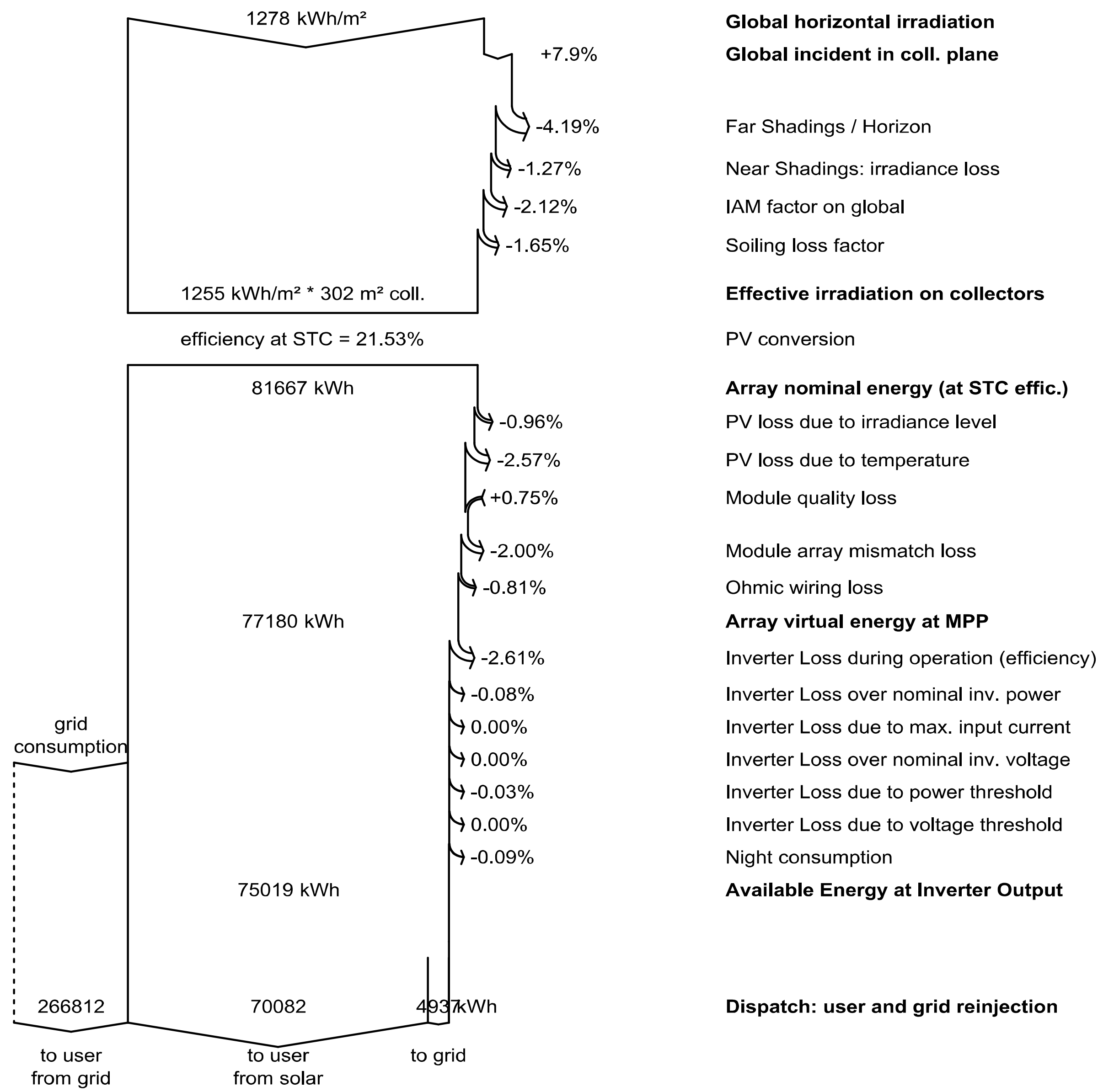
Balances and main results

	GlobHor	DiffHor	T_Amb	GlobInc	GlobEff	EArray	E_User	E_Solar	E_Grid	EFrGrid
	kWh/m²	kWh/m²	°C	kWh/m²	kWh/m²	kWh	kWh	kWh	kWh	kWh
January	37.1	24.55	-4.95	46.2	37.7	2494	35764	2395	-7	33368
February	64.6	32.19	-4.73	78.2	67.7	4437	31466	4318	-6	27149
March	108.9	52.41	-0.87	124.8	111.5	7189	34860	7013	-5	27847
April	133.2	68.46	4.86	142.2	129.9	8128	27685	7490	433	20195
May	166.9	90.47	10.82	168.8	157.1	9624	28124	8826	564	19298
June	174.2	81.62	15.80	174.4	164.2	9795	27133	8740	811	18393
July	168.8	83.39	20.58	169.2	158.0	9300	23799	7921	1139	15879
August	155.7	76.12	19.93	162.4	150.1	8847	23950	7570	1054	16380
September	120.2	52.54	15.56	132.9	121.6	7325	22253	6231	904	16022
October	76.8	46.50	9.65	88.4	80.2	5004	25817	4799	64	21019
November	41.0	24.01	4.04	51.1	44.2	2818	26906	2717	-7	24190
December	30.5	18.32	-1.27	39.9	33.1	2158	29137	2064	-7	27073
Year	1277.8	650.56	7.52	1378.3	1255.2	77120	336894	70082	4937	266812

Legends

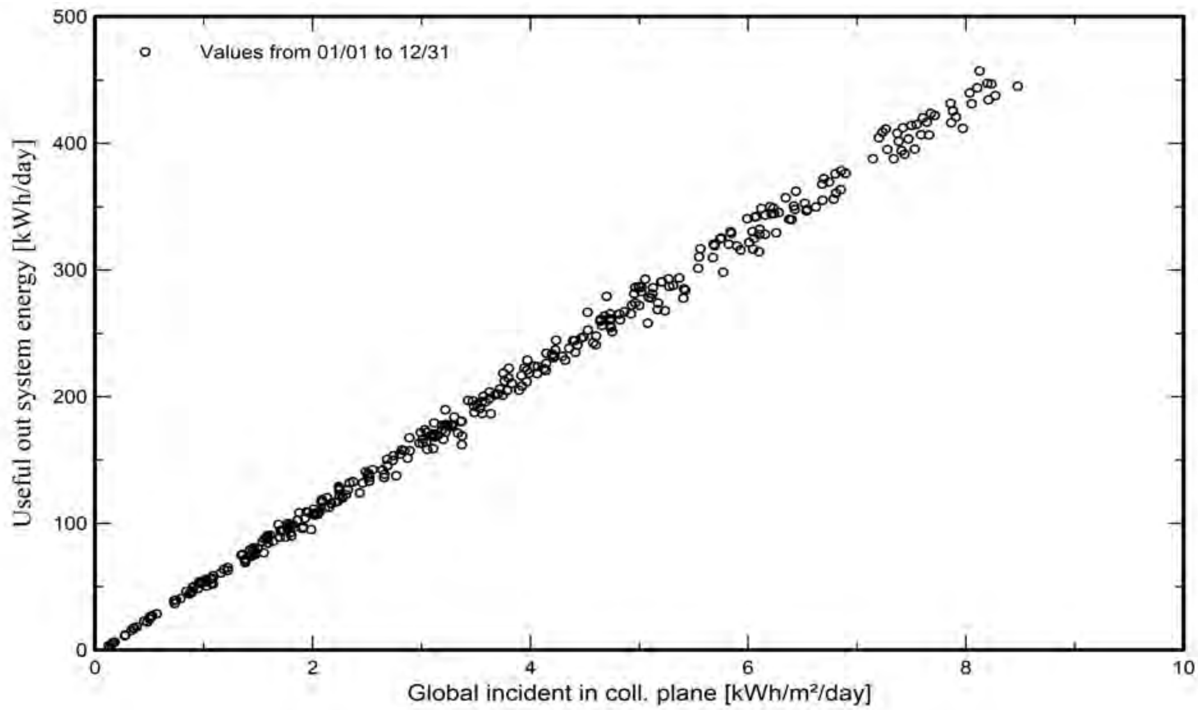
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

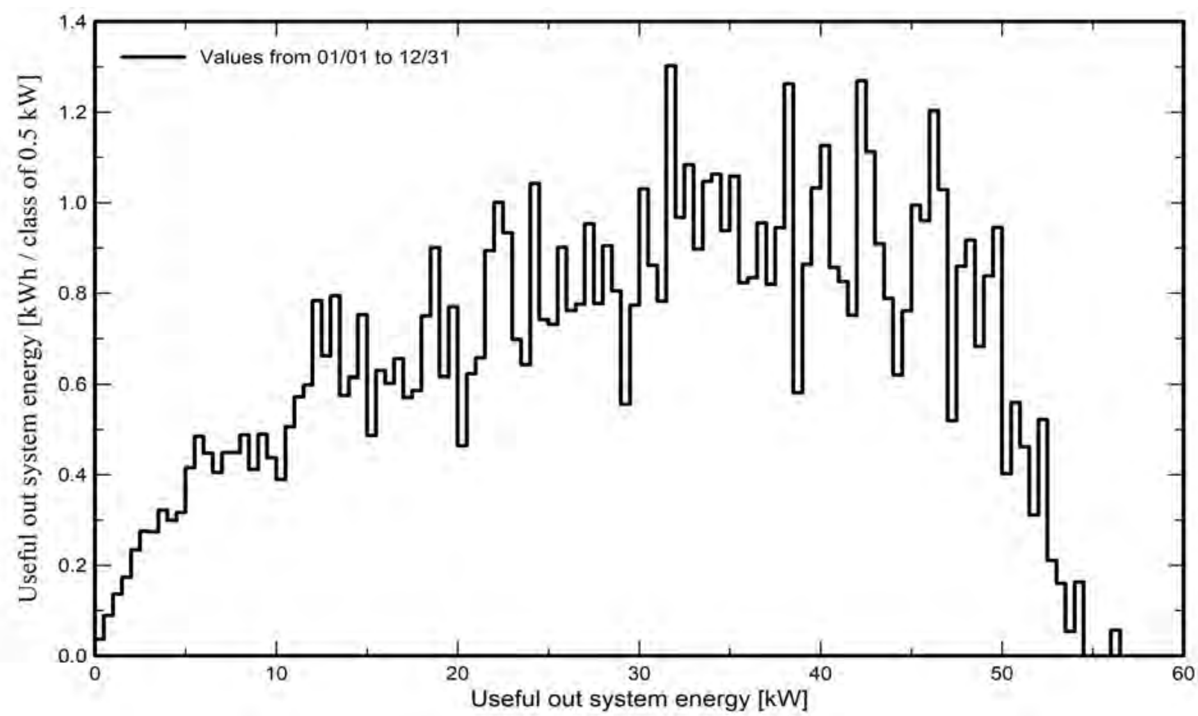


Predef. graphs

Daily Input/Output diagram

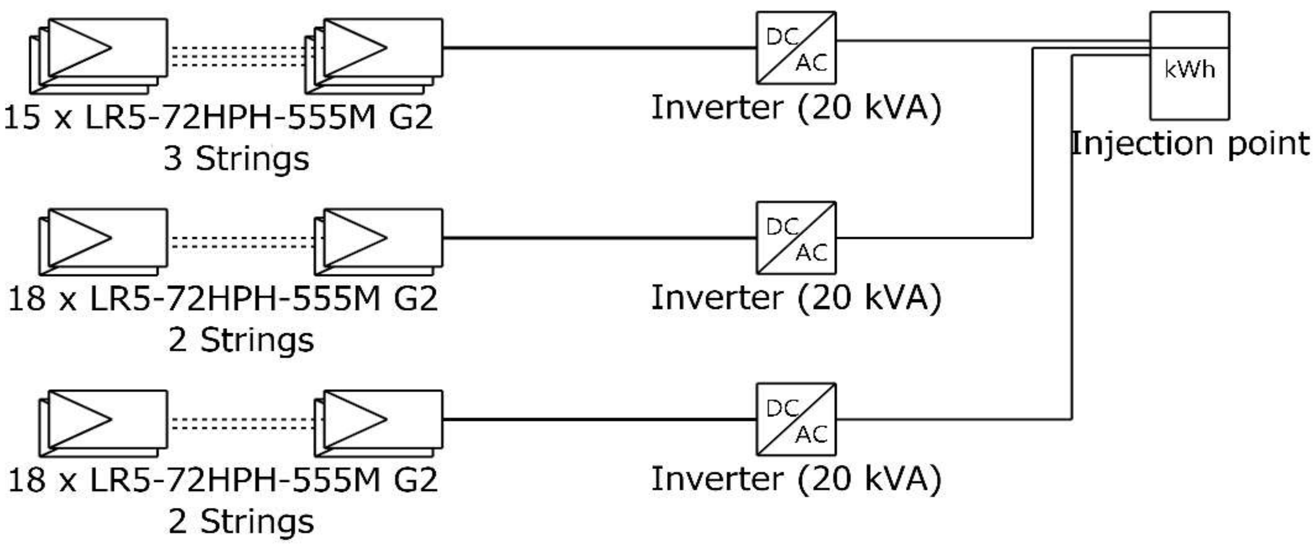


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC2, Simulation date:
08/14/24 14:41
with V7.4.8



PV module	LR5-72HPH-555M G2
Inverter	Sunny Tripower X - STP20-US-50
String 1	15 x LR5-72HPH-555M G2
String 2	18 x LR5-72HPH-555M G2

	Windsor Water Treatment Plant	CBCL Limited (Canada)
	VC2 : Windsor Water Treatment Plant 64.9 kW ground & roof MONO	08/14/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 786 Windsor Back Road:Windsor Water Treatment Plant

Variant: Windsor Water Treatment Plant 113kW due south MONO

Sheds on ground

System power: 113 kWp

786 Windsor Back Rd: Windsor WTP - Canada

Author

CBCL Limited (Canada)

Project: 786 Windsor Back Road:Windsor Water Treatment Plant

Variant: Windsor Water Treatment Plant 113kW due south MONO

CBCL Limited (Canada)

Project summary

Geographical Site
786 Windsor Back Rd: Windsor WTP
Canada

Situation

Latitude	44.96 °N
Longitude	-64.12 °W
Altitude	14 m
Time zone	UTC-4

Project settings

Albedo	0.20

Weather data
786 Windsor Back Rd: Windsor WTP
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System

Sheds on ground

PV Field Orientation
Fixed plane
Tilt/Azimuth 30 / 0 °

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

System information

PV Array

Nb. of modules	204 units
Pnom total	113 kWp

Inverters

Nb. of units	3 units
Pnom total	99.9 kWac
Pnom ratio	1.133

Results summary

Produced Energy	140714 kWh/year	Specific production	1243 kWh/kWp/year	Perf. Ratio PR	84.78 %
Used Energy	336894 kWh/year			Solar Fraction SF	28.73 %

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Near shading definition - Iso-shadings diagram 6
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General parameters

Grid-Connected System

Sheds on ground

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 30 / 0 °

Sheds configuration
Nb. of sheds 8 units
Identical arrays
Sizes
Sheds spacing 10.4 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 44.2 %
Top inactive band 0.02 m
Bottom inactive band 0.02 m
Shading limit angle
Limit profile angle 19.8 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Average Height 6.8 °

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
35.8	31.5	34.9	27.7	28.1	27.1	23.8	24.0	22.3	25.8	26.9	29.1	337	MWh

PV Array Characteristics

PV module
Manufacturer Longi Solar
Model LR5-72HPH-555M G2
(Original PVsyst database)
Unit Nom. Power 555 Wp
Number of PV modules 204 units
Nominal (STC) 113 kWp
Modules 12 string x 17 In series
At operating cond. (50°C)
Pmpp 104 kWp
U mpp 643 V
I mpp 161 A

Inverter
Manufacturer SMA
Model Sunny Tripower STP33-US-41-Core1
(Original PVsyst database)
Unit Nom. Power 33.3 kWac
Number of inverters 3 units
Total power 99.9 kWac
Operating voltage 150-800 V
Pnom ratio (DC:AC) 1.13
Power sharing within this inverter

Total PV power
Nominal (STC) 113 kWp
Total 204 modules
Module area 527 m²
Cell area 489 m²

Total inverter power
Total power 100 kWac
Number of inverters 3 units
Pnom ratio 1.13

Array losses

Array Soiling Losses
Average loss Fraction 2.2 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
6.0%	5.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	2.0%	3.0%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 20.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 66 mΩ
Loss Fraction 1.5 % at STC

Module Quality Loss
Loss Fraction -0.8 %

Array losses

Module mismatch losses

Loss Fraction 2.0 % at MPP

IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

Horizon definition

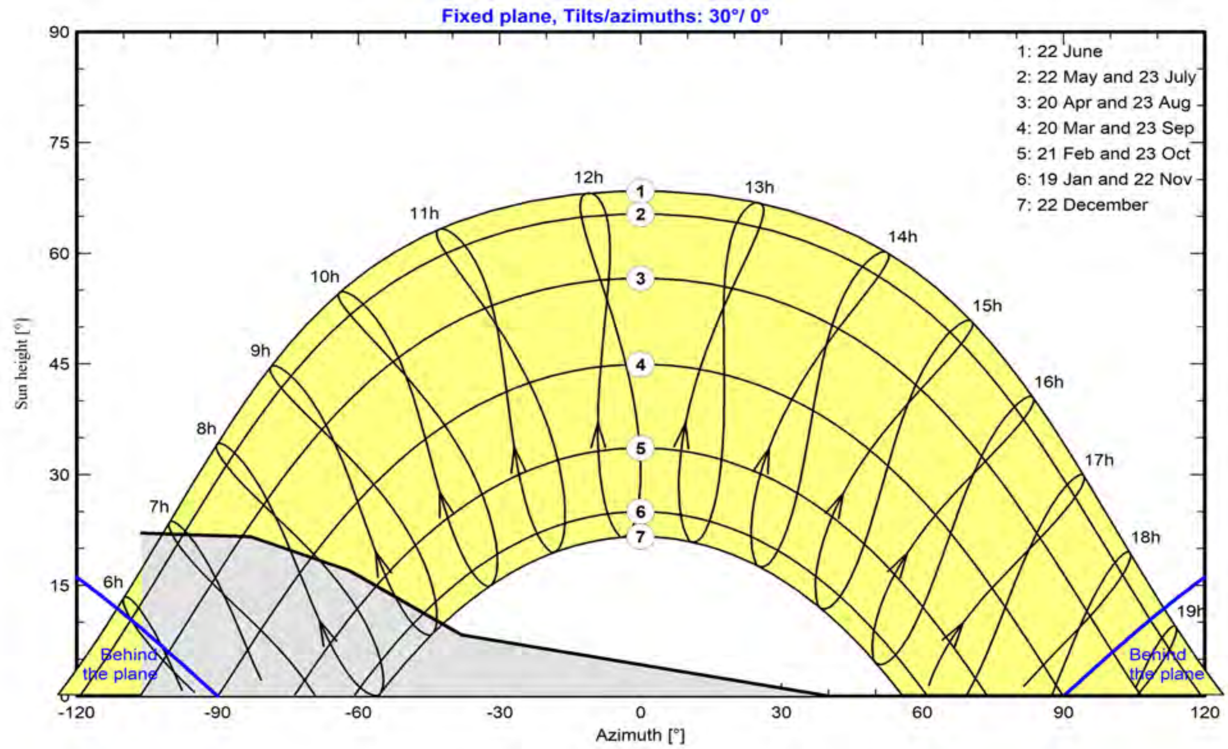
Horizon line at 786 Windsor Back Rd: Windsor WTP

Average Height	6.8 °	Albedo Factor	0.76
Diffuse Factor	0.95	Albedo Fraction	100 %

Horizon profile

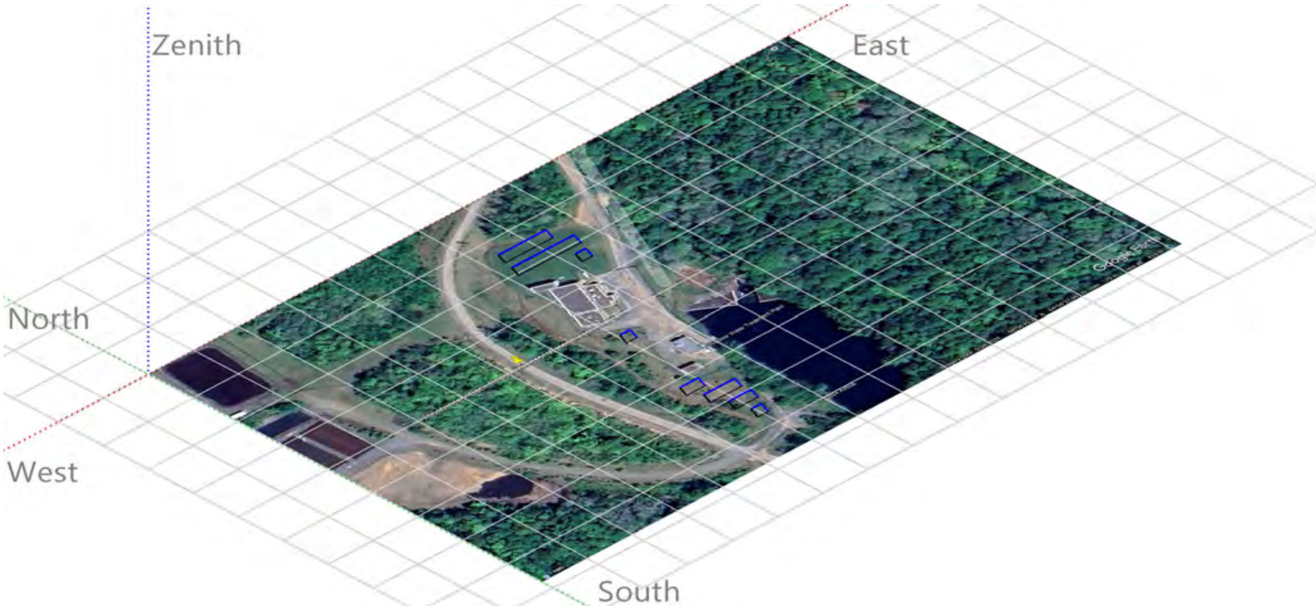
Azimuth [°]	-106	-83	-62	-38	40	120
Height [°]	22.1	21.6	17.0	8.3	0.0	0.0

Sun Paths (Height / Azimuth diagram)



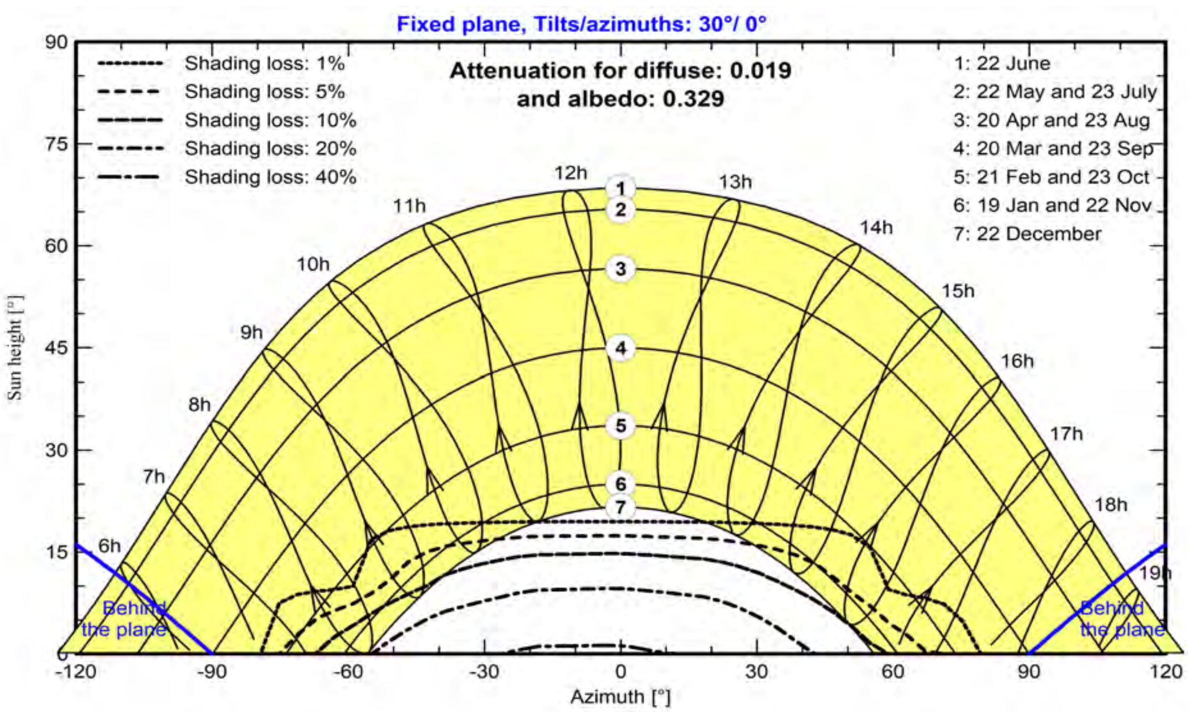
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

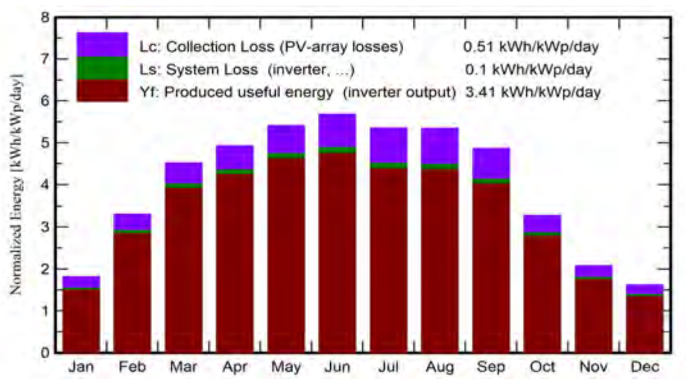


Main results

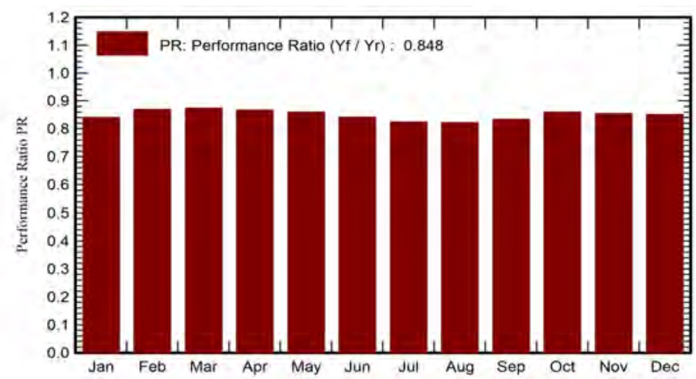
System Production

Produced Energy	140714 kWh/year	Specific production	1243 kWh/kWp/year
Used Energy	336894 kWh/year	Perf. Ratio PR	84.78 %
		Solar Fraction SF	28.73 %

Normalized productions (per installed kWp)



Performance Ratio PR



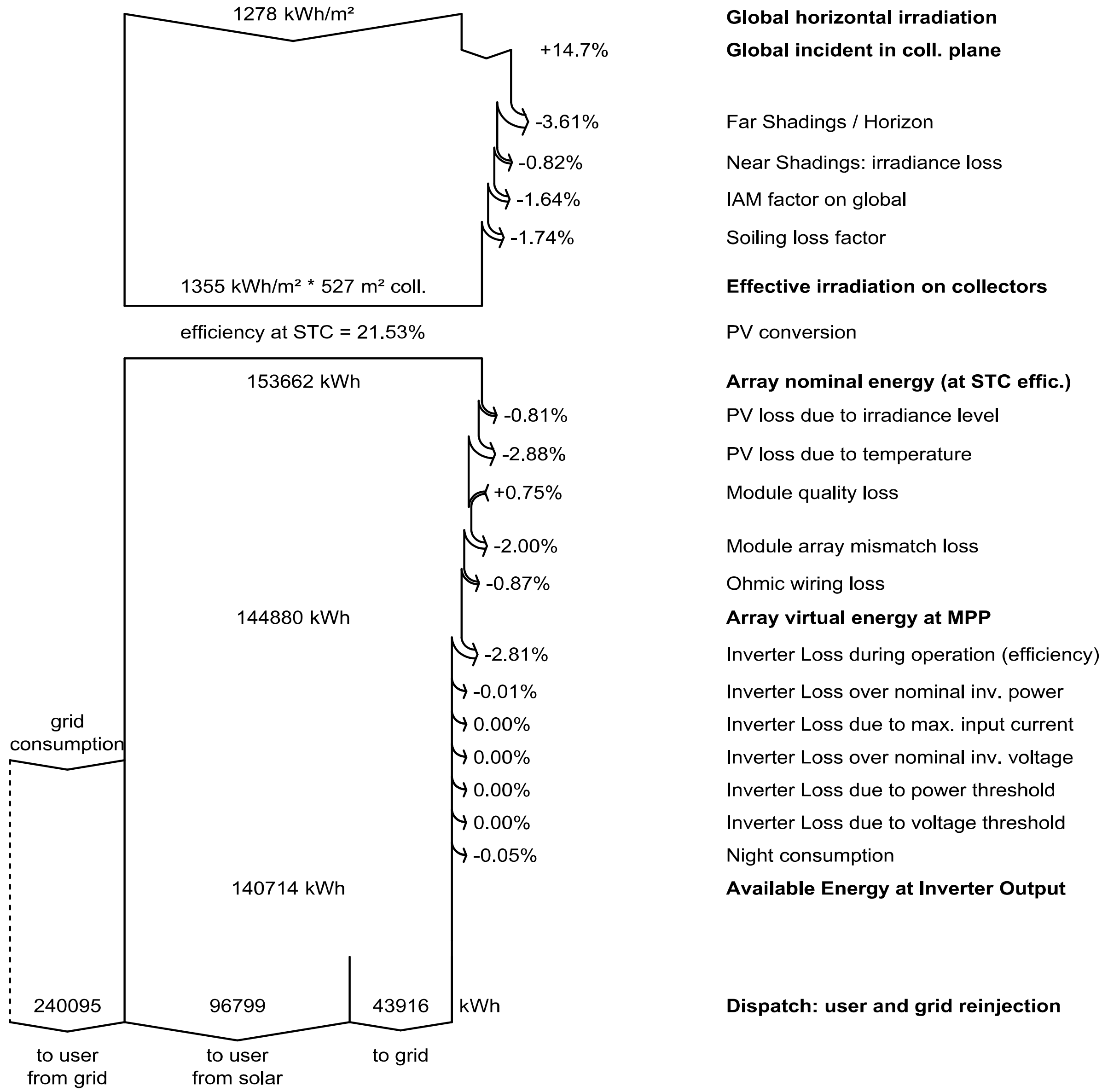
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.1	24.55	-4.95	56.3	48.3	5536	35764	4963	390	30800
February	64.6	32.19	-4.73	92.5	82.5	9352	31466	7247	1858	24220
March	108.9	52.41	-0.87	140.0	127.3	14212	34860	10523	3321	24337
April	133.2	68.46	4.86	147.7	137.1	14913	27685	9738	4771	17947
May	166.9	90.47	10.82	167.6	157.0	16766	28124	11092	5208	17032
June	174.2	81.62	15.80	170.3	160.7	16701	27133	10572	5646	16561
July	168.8	83.39	20.58	166.0	155.6	15948	23799	9683	5793	14116
August	155.7	76.12	19.93	165.7	155.0	15864	23950	9174	6233	14776
September	120.2	52.54	15.56	145.8	135.9	14158	22253	7880	5877	14373
October	76.8	46.50	9.65	101.5	94.2	10173	25817	7196	2686	18621
November	41.0	24.01	4.04	62.3	56.5	6231	26906	4731	1297	22175
December	30.5	18.32	-1.27	50.2	44.3	5010	29137	3999	835	25137
Year	1277.8	650.56	7.52	1465.9	1354.5	144865	336894	96799	43916	240095

Legends

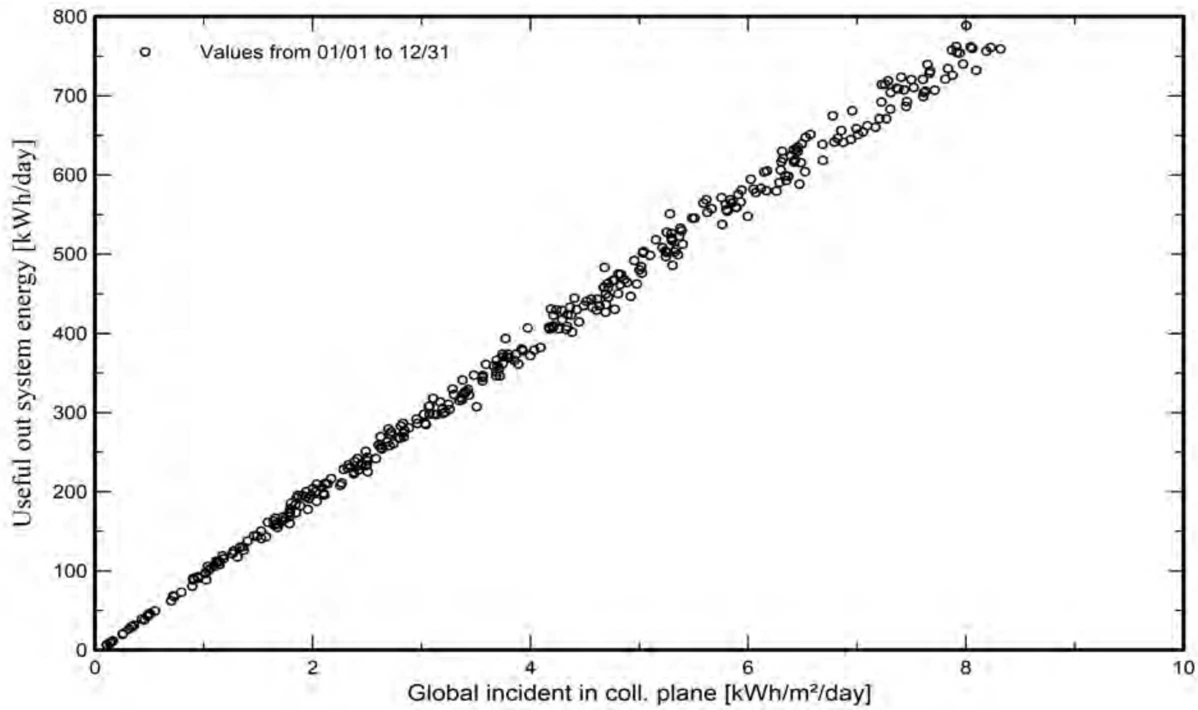
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

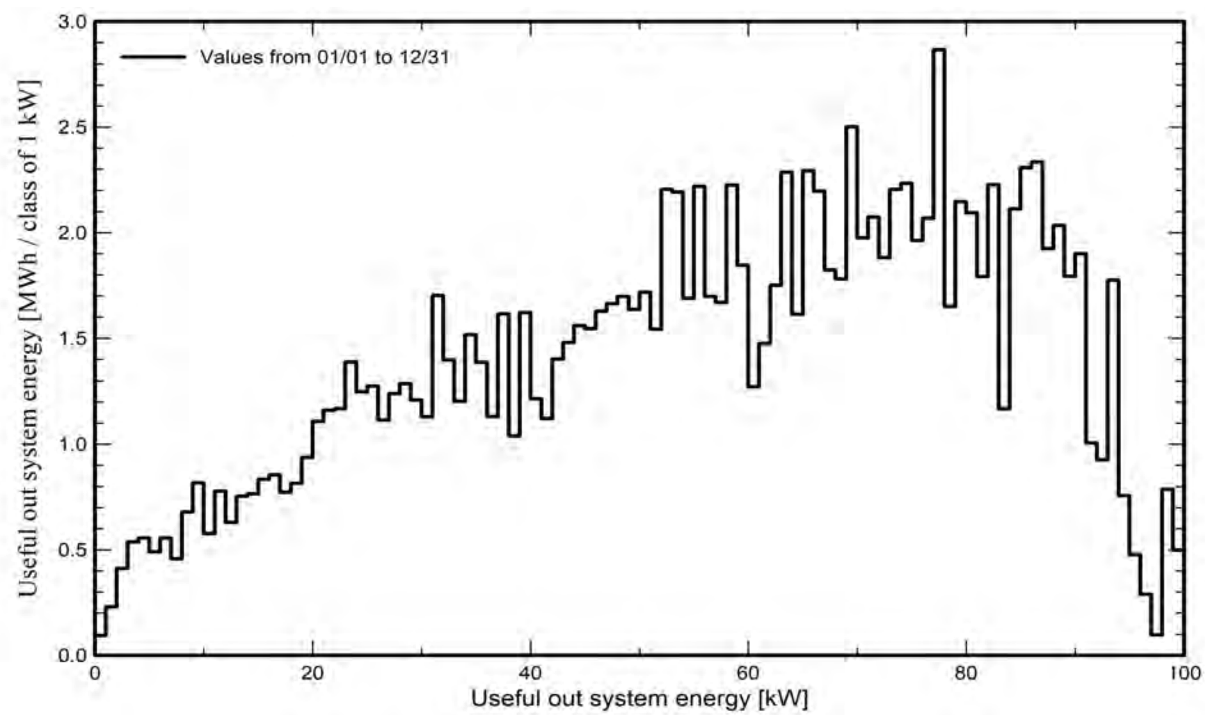


Predef. graphs

Daily Input/Output diagram

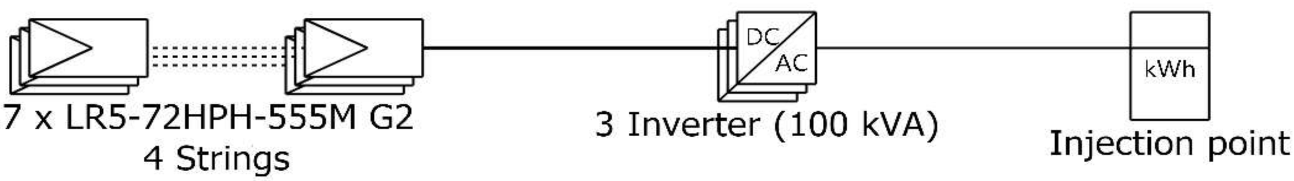


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC0, Simulation date:
08/14/24 13:30
with V7.4.8



PV module	LR5-72HPH-555M G2
Inverter	Sunny Tripower STP33-US-41-Core1
String	17 x LR5-72HPH-555M G2

Windsor Water Treatment Plant	CBCL Limited (Canada)
VC0 : Windsor Water Treatment Plant 113kW due south MONO	08/14/24

Version 7.4.8

PVsyst - Simulation report

Grid-Connected System

Project: 786 Windsor Back Road:Windsor Water Treatment Plant

Variant: Windsor Water Treatment Plant 113kW due south BIFACIAL

Sheds on ground

System power: 113 kWp

786 Windsor Back Rd: Windsor WTP - Canada

Author

CBCL Limited (Canada)

Project: 786 Windsor Back Road:Windsor Water Treatment Plant

Variant: Windsor Water Treatment Plant 113kW due south BIFACIAL

PVsyst V7.4.8
VC1, Simulation date:
08/14/24 13:31
with V7.4.8

CBCL Limited (Canada)

Project summary

Geographical Site	Situation		Project settings	
786 Windsor Back Rd: Windsor WTP	Latitude	44.96 °N	Albedo	0.20
Canada	Longitude	-64.12 °W		
	Altitude	14 m		
	Time zone	UTC-4		

Weather data
786 Windsor Back Rd: Windsor WTP
Meteonorm 8.1 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System | **Sheds on ground**

PV Field Orientation		Near Shadings	User's needs
Fixed plane		Linear shadings : Fast (table)	Monthly values
Tilt/Azimuth	30 / 0 °		

System information

PV Array		Inverters	
Nb. of modules	204 units	Nb. of units	3 units
Pnom total	113 kWp	Pnom total	99.9 kWac
		Pnom ratio	1.133

Results summary

Produced Energy	150941 kWh/year	Specific production	1333 kWh/kWp/year	Perf. Ratio PR	90.95 %
Used Energy	336894 kWh/year			Solar Fraction SF	29.85 %

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General parameters

Grid-Connected System

Sheds on ground

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 30 / 0 °

Sheds configuration
Nb. of sheds 8 units
Identical arrays

Sizes
Sheds spacing 10.4 m
Collector width 4.58 m
Ground Cov. Ratio (GCR) 44.2 %
Top inactive band 0.02 m
Bottom inactive band 0.02 m

Shading limit angle
Limit profile angle 19.8 °

Models used
Transposition Perez
Diffuse Perez, Meteonorm
Circumsolar separate

Horizon
Average Height 6.2 °

Near Shadings
Linear shadings : Fast (table)

User's needs
Monthly values

Bifacial system
Model 2D Calculation
unlimited sheds

Bifacial model geometry
Sheds spacing 10.36 m
Sheds width 4.62 m
Limit profile angle 19.8 °
GCR 44.6 %
Height above ground 1.50 m

Bifacial model definitions
Ground albedo 0.30
Bifaciality factor 70 %
Rear shading factor 5.0 %
Rear mismatch loss 10.0 %
Shed transparent fraction 0.0 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year	
35.8	31.5	34.9	27.7	28.1	27.1	23.8	24.0	22.3	25.8	26.9	29.1	337	MWh

PV Array Characteristics

PV module
Manufacturer Longi Solar
Model LR5-72HBD-555M G2 Bifacial
(Original PVsyst database)
Unit Nom. Power 555 Wp
Number of PV modules 204 units
Nominal (STC) 113 kWp
Modules 12 string x 17 In series

At operating cond. (50°C)
Pmpp 104 kWp
U mpp 645 V
I mpp 161 A

Inverter
Manufacturer SMA
Model Sunny Tripower STP33-US-41-Core1
(Original PVsyst database)
Unit Nom. Power 33.3 kWac
Number of inverters 3 units
Total power 99.9 kWac
Operating voltage 150-800 V
Pnom ratio (DC:AC) 1.13
Power sharing within this inverter

Total PV power
Nominal (STC) 113 kWp
Total 204 modules
Module area 527 m²
Cell area 489 m²

Total inverter power
Total power 100 kWac
Number of inverters 3 units
Pnom ratio 1.13

Array losses

Array Soiling Losses

Average loss Fraction 2.2 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
6.0%	5.0%	3.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	2.0%	3.0%

Thermal Loss factor

Module temperature according to irradiance

Uc (const) 20.0 W/m²K

Uv (wind) 0.0 W/m²K/m/s

DC wiring losses

Global array res. 66 mΩ

Loss Fraction 1.5 % at STC

Module Quality Loss

Loss Fraction -0.8 %

Module mismatch losses

Loss Fraction 2.0 % at MPP

IAM loss factor

Incidence effect (IAM): User defined profile

0°	25°	45°	60°	65°	70°	75°	80°	90°
1.000	1.000	0.995	0.962	0.936	0.903	0.851	0.754	0.000

Horizon definition

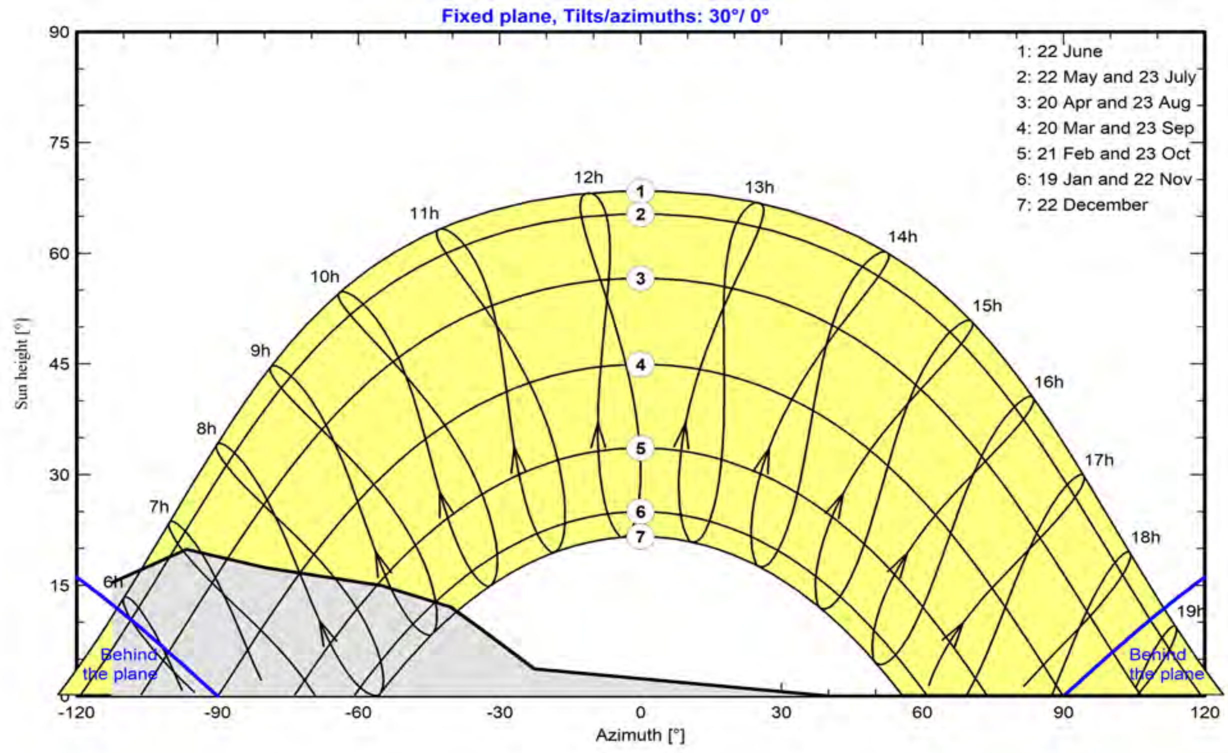
Horizon line at 786 Windsor Back Rd: Windsor WTP

Average Height	6.2 °	Albedo Factor	0.80
Diffuse Factor	0.96	Albedo Fraction	100 %

Horizon profile

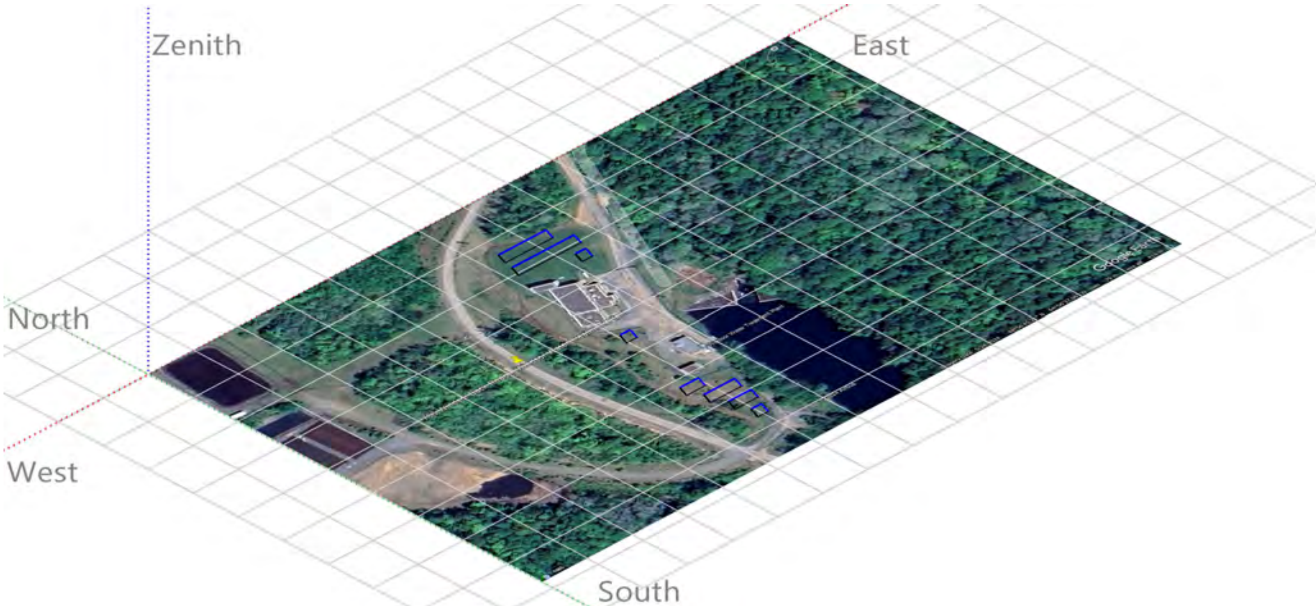
Azimuth [°]	-112	-97	-80	-55	-41	-34	-23	40	120
Height [°]	15.4	19.9	17.4	15.0	12.1	9.2	3.7	0.0	0.0

Sun Paths (Height / Azimuth diagram)



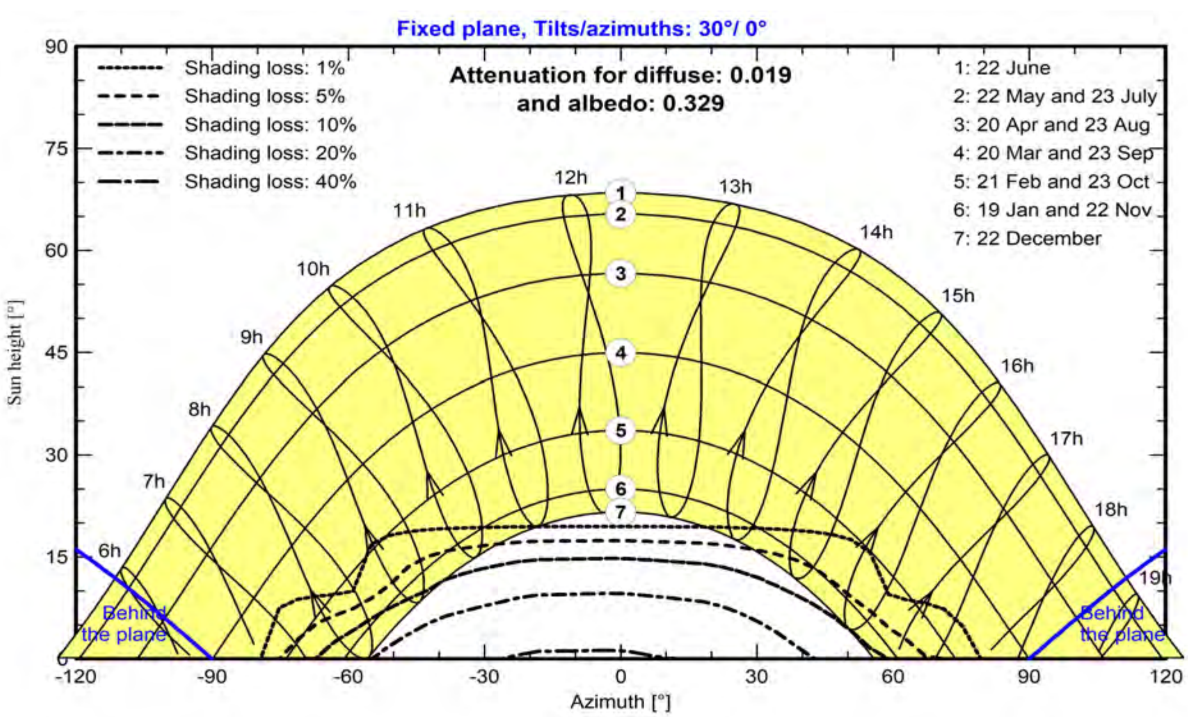
Near shadings parameter

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

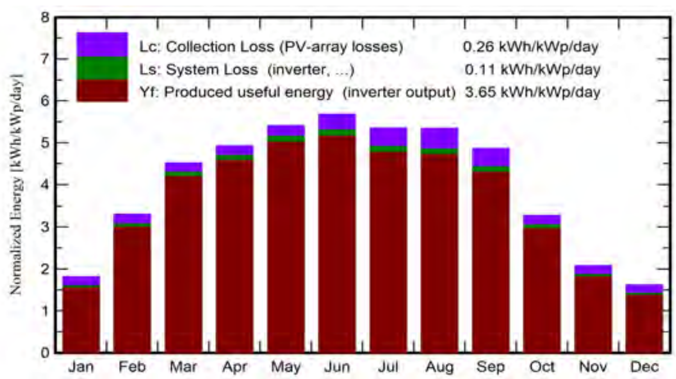


Main results

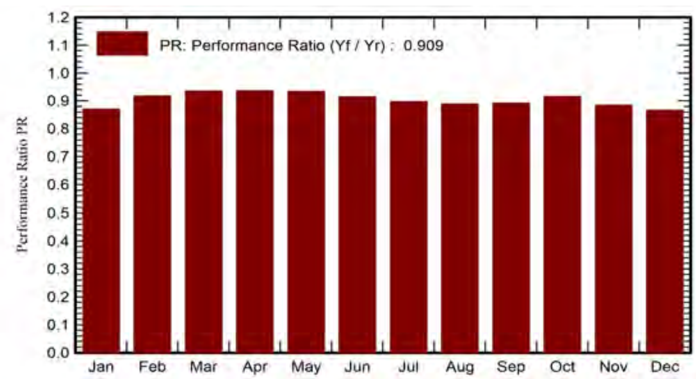
System Production

Produced Energy	150941 kWh/year	Specific production	1333 kWh/kWp/year
Used Energy	336894 kWh/year	Perf. Ratio PR	90.95 %
		Solar Fraction SF	29.85 %

Normalized productions (per installed kWp)



Performance Ratio PR



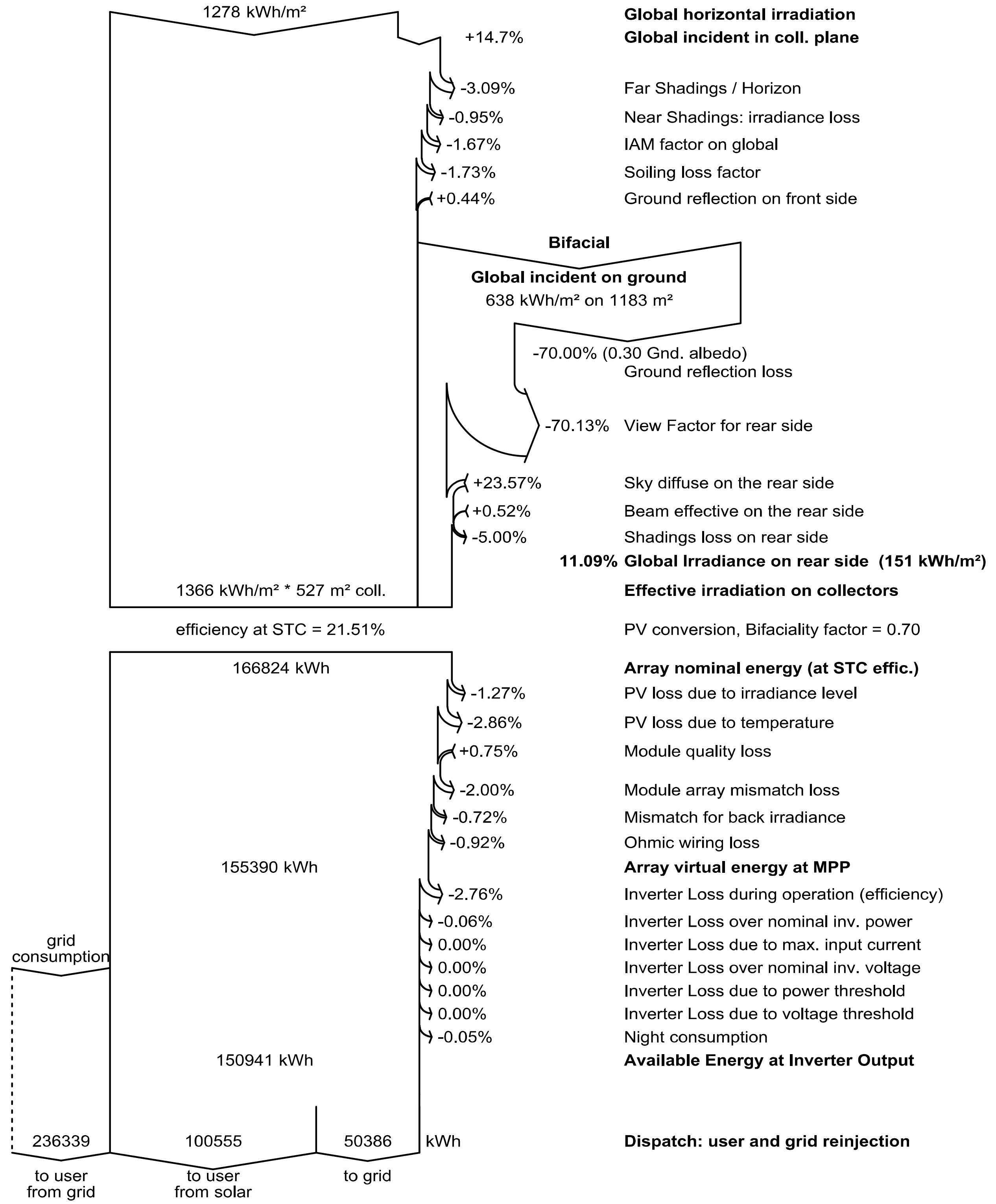
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_User kWh	E_Solar kWh	E_Grid kWh	EFrGrid kWh
January	37.1	24.55	-4.95	56.3	48.0	5729	35764	5112	430	30651
February	64.6	32.19	-4.73	92.5	82.7	9870	31466	7480	2131	23986
March	108.9	52.41	-0.87	140.0	128.8	15208	34860	10894	3926	23965
April	133.2	68.46	4.86	147.7	139.1	16078	27685	10185	5468	17500
May	166.9	90.47	10.82	167.6	158.6	18215	28124	11571	6150	16553
June	174.2	81.62	15.80	170.3	162.1	18155	27133	11086	6556	16047
July	168.8	83.39	20.58	166.0	157.1	17372	23799	10140	6730	13660
August	155.7	76.12	19.93	165.7	156.9	17153	23950	9586	7083	14364
September	120.2	52.54	15.56	145.8	137.4	15141	22253	8163	6556	14089
October	76.8	46.50	9.65	101.5	94.8	10832	25817	7434	3094	18383
November	41.0	24.01	4.04	62.3	56.2	6448	26906	4833	1409	22074
December	30.5	18.32	-1.27	50.2	43.8	5099	29137	4071	852	25066
Year	1277.8	650.56	7.52	1465.9	1365.5	155300	336894	100555	50386	236339

Legends

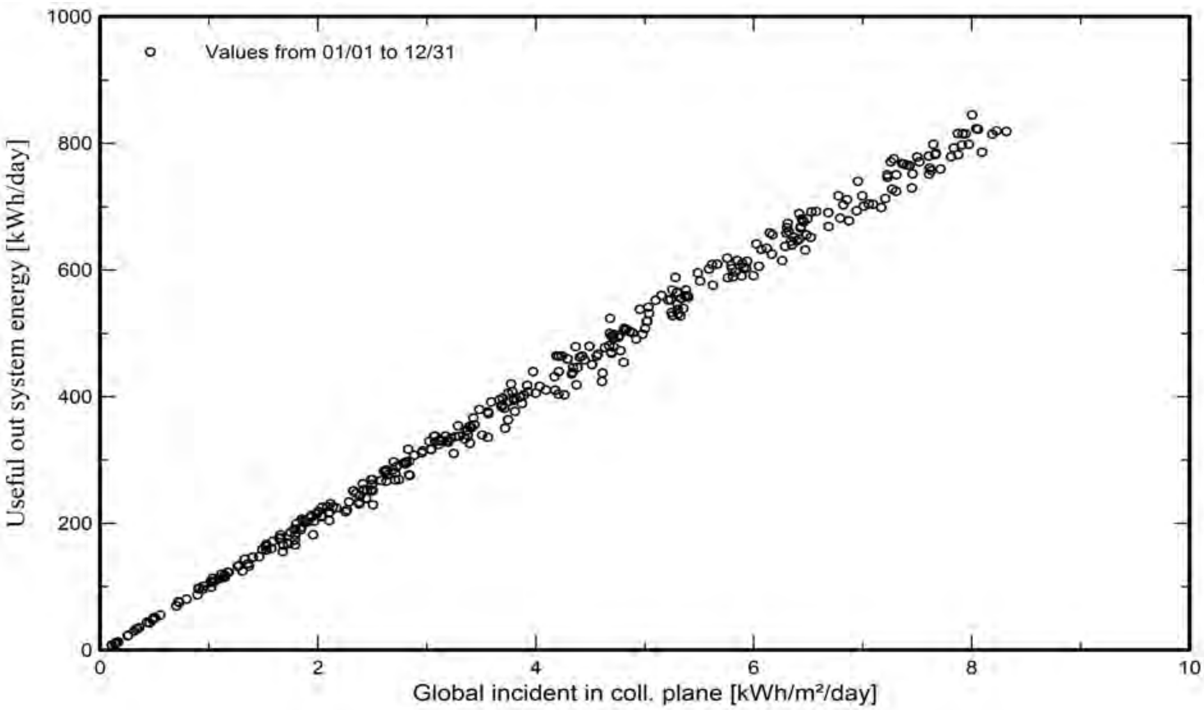
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_User	Energy supplied to the user
T_Amb	Ambient Temperature	E_Solar	Energy from the sun
GlobInc	Global incident in coll. plane	E_Grid	Energy injected into grid
GlobEff	Effective Global, corr. for IAM and shadings	EFrGrid	Energy from the grid

Loss diagram

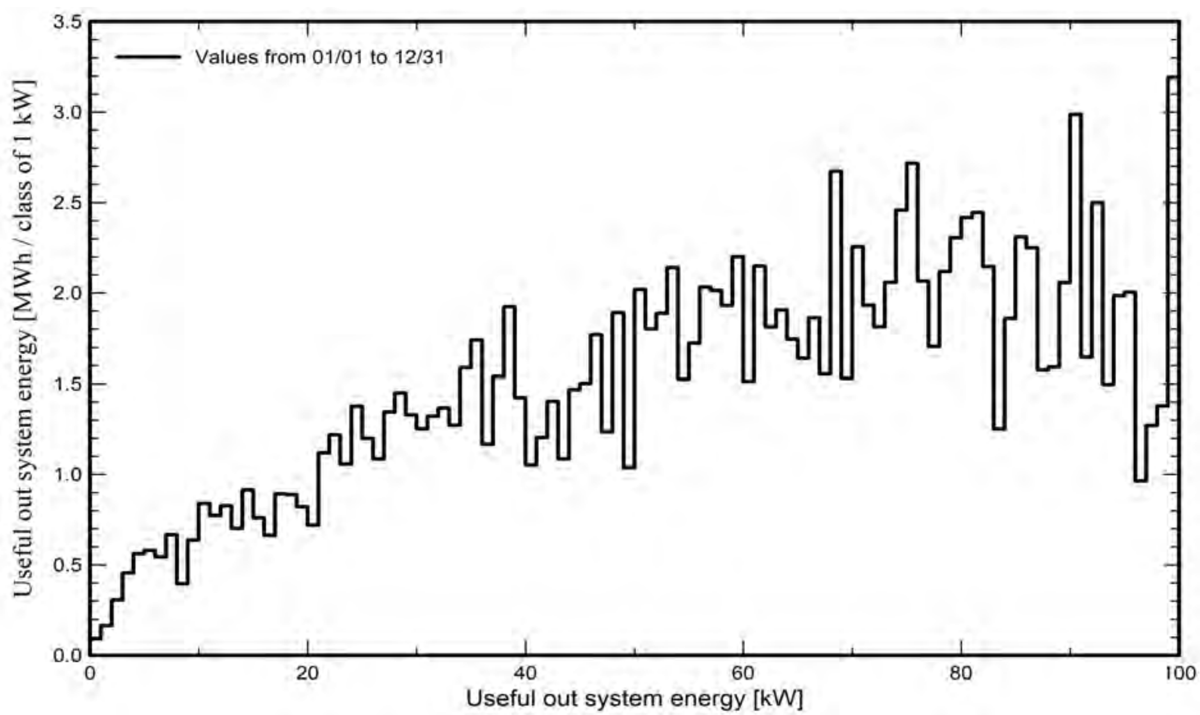


Predef. graphs

Daily Input/Output diagram

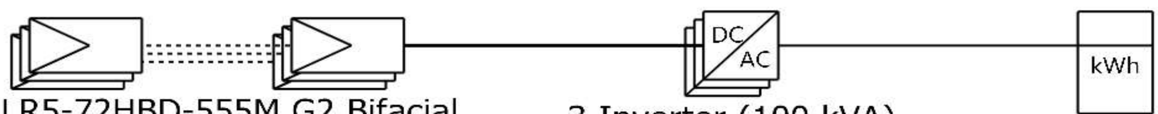


System Output Power Distribution



Single-line diagram

PVsyst V7.4.8
VC1, Simulation date:
08/14/24 13:31
with V7.4.8



17 x LR5-72HBD-555M G2 Bifacial
4 Strings

3 Inverter (100 kVA)

Injection point

PV module	LR5-72HBD-555M G2 Bifacial
Inverter	Sunny Tripower STP33-US-41-Core1
String	17 x LR5-72HBD-555M G2 Bifacial

Windsor Water Treatment Plant	CBCL Limited (Canada)
VC1 : Windsor Water Treatment Plant 113kW due south BIFACIAL	08/14/24

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